Atlantic Power Corporation

# 2017
# Annual Report

## Report to Shareholders

Dear Shareholder,

This year's letter is divided into three sections: first, a review of the progress we have made in restructuring and turning around the business over the past three years; second, a summary of our 2017 results and the outlook for 2018; and third, a discussion of trends affecting the power markets, how Atlantic Power Corporation (the "Company") is positioned in the current environment, and our views on growth and capital allocation.

### 2015 – 2017 RESTRUCTURING RESULTS

2017 represented the third year of our restructuring efforts. Our focus during this period has been on reducing debt and interest costs by reshaping our balance sheet, reducing corporate overheads, and rolling out a program to reduce operating costs. Our goal is to position the Company for the long haul, in a challenging commodity price environment when several of our above-market Power Purchase Agreements (PPAs) have expired or will expire in the next several years. As a result of these steps, summarized below, we now have an improved credit profile and liquidity of approximately $205 million.

**Debt.** We reduced consolidated debt by $909 million, from $1,755 million at year-end 2014 to $846 million at year-end 2017. We accomplished this by debt amortization, discretionary debt repurchases, and asset sales. During this period our leverage ratio[1] declined from 6.9 times to 3.3 times. We plan to repay another $100 million of debt in 2018, although we expect our leverage ratio will increase to the high 4 times range because of lower Project Adjusted EBITDA,[2] before beginning to decline again in 2019 and beyond. We also significantly improved our debt maturity profile during this period as a result of debt repayment and refinancing activity. At year-end 2014, we had $671 million of bullet maturities in the following five years, but by March 2018, we had reduced the five-year total to approximately $20 million (all in 2019). We expect to amortize approximately $470 million of term loan and project debt from 2018 through 2022.

**Interest payments.** The significant reduction in our debt during this period reduced our cash interest payments from $127 million in 2014 (not including $42 million of non-recurring cash costs associated with redemptions and refinancing transactions) to $72 million in 2017. We expect a further reduction in 2018, to an estimated $45 million. In addition to the reduction in our debt, the three re-pricings of our senior secured term loan and revolver since April 2017 have reduced the cost of those facilities to us and contributed to the reduction in cash interest payments in 2017 and beyond.

**Corporate overheads.** We reduced corporate general and administrative (G&A) expense by slightly more than half, from $45 million in 2014 to $22 million in 2017. To accomplish this, we reduced our corporate staff from 66 at the end of 2014 to 44 currently (at the beginning of 2013, prior to my tenure as CEO, the number of corporate employees peaked at 110). We also moved the corporate headquarters from Boston to Dedham, Massachusetts, in 2015, which reduced our annual rent from approximately $1.2 million to $500,000. Later this year we will be relocating to a smaller space within our current building. As a result, we will further reduce the rent for our headquarters to $285,000 annually.

The combination of lower corporate overheads and lower cash interest payments resulted in $78 million of recurring cash savings to the Company in 2017 relative to 2014, and we expect approximately $27 million of additional interest cost savings in 2018.

**Assets divested or mothballed.** In 2015, we sold all five of our wind plants (with a combined capacity of 521 megawatts) for $350 million of net proceeds, or approximately 13.5 times estimated cash distributions, and used the proceeds to redeem our remaining $311 million of 9% senior unsecured notes. The transaction was $2 million accretive to our cash flow, and we improved our leverage ratio and debt maturity profile. Separately, in early 2017, we mothballed (took out of operation for an extended period) three plants in Ontario totaling 120 megawatts of generating capacity. This was the result of a revised contractual arrangement with the plants' customer, which produced benefits for us and for ratepayers. We will return the Nipigon plant to service in November of this year, while the Kapuskasing and North Bay plants have option value should the supply and demand balance in Ontario improve at some point, or if we are successful in repurposing the sites.

**Investment in our plants.** In 2013 through 2016, we made $25 million of optimization investments in our existing plants, to improve efficiency, increase capacity, and reduce operating costs. In 2013 through 2017, we realized a cumulative cash return of approximately $32 million on these investments, and we expect a recurring cash flow contribution of $11 million to $12 million annually in 2018 and beyond. The returns on these investments were higher than what we could have achieved externally and carried lower risk, because we know these assets well.

**Culture.** Atlantic Power is a "servant leadership company," meaning we believe leadership is a skill that can be developed. Servant leaders seek to build authority through their actions and strive to act with respect, integrity, and honesty. Servant leaders seek to be good listeners, to be humble, and to lead by example. We seek to build a safe environment for dissent, where bad news is communicated in nanoseconds and we stay well away from legal and ethical boundaries. This allows us to get problems on the table quickly and honestly so they can be dealt with by the team. This also allows us to face reality, which is necessary for good execution in our business. The best exposition of servant leadership principles we have found is in the books of James C. Hunter (*The Servant: A Simple Story About the True Essence of Leadership*; *The World's Most Powerful Leadership Principle: How to Become a Servant Leader*, and *The Culture: Creating Excellence with Those You Lead*).

**REVIEW OF 2017 FINANCIAL RESULTS**

We posted strong financial results in 2017 as measured by Project Adjusted EBITDA and operating cash flow. Both metrics met or exceeded our estimates, which were revised upward twice in 2017.

**Project Adjusted EBITDA** of $289 million was $87 million higher than the 2016 level of $202 million. This significant increase was driven primarily by the favorable impact of the revised contractual and operational arrangements for three of our Ontario plants (Kapuskasing, North Bay, and Nipigon) and the expiration of an above-market gas contract in Ontario (together totaling $42 million), the settlement of the Global Adjustment litigation in Ontario (the OEFC Settlement; $29 million), increased water flows at Curtis Palmer ($13 million), more modest increases at several other plants, including Orlando and Morris, and a $3 million non-cash translation benefit to EBITDA from the appreciation of the Canadian dollar. Partially offsetting these positive factors, we had modest decreases at our Mamquam, Frederickson and Calstock plants.

**Cash provided by operating activities** of $169 million increased by $57 million from the 2016 level of $112 million. In 2017, we collected approximately $27 million of cash under the OEFC Settlement. Other factors that helped cash flow included the higher EBITDA at our Kapuskasing, North Bay, and Nipigon plants and the benefit to EBITDA from higher water flows at Curtis Palmer. These positive factors were partially offset by modest decreases at our Mamquam, Frederickson, and Kenilworth plants. In addition, cash provided by operating activities was reduced $24 million from 2016 due to changes in working capital.

A review of our business and financial results for 2017 immediately follows this letter.

## 2018 OUTLOOK

On our year-end 2017 conference call last month, we again indicated that we expect a significant decline in Project Adjusted EBITDA and operating cash flow in 2018. This is the result of several factors. In December 2017, as expected, the contracts for our Kapuskasing and North Bay plants expired and were not renewed. Also in December 2017, we executed a short-term extension of the contract for our Williams Lake plant. The EBITDA contribution under the amended contract is expected to be *de minimis*. In early February 2018, we shut down operations of our three plants in San Diego because we have not been successful in obtaining permission from the U.S. Navy to remain on site. We expect these developments, together with the non-recurrence of the OEFC Settlement revenues recorded in 2017, to reduce our Project Adjusted EBITDA by approximately $105 million in 2018 compared to 2017. In addition, there are other factors, both positive and negative, that will affect the level of EBITDA, but these are considerably more modest in terms of potential impact. The reduction in our operating cash flow should be less because we expect our cash interest payments to be approximately $27 million lower in 2018 than they were in 2017.

## POWER MARKETS OVERVIEW

The most significant change in energy markets in recent years has been the combination of fracking, horizontal drilling and 3-D seismic, which has revolutionized oil and gas production in the United States. The impact on production levels and costs has fundamentally shifted the supply and price environment of oil and gas in the United States and globally. Not that long ago, I handed out copies of a book on peak oil to the board of a wind energy company and we thought that LNG terminals were needed for imports. Since then, the world has been turned upside down.

The results of this technological revolution have changed the supply picture for fossil fuels in the United States for the foreseeable future. Low natural gas prices in turn have hurt the economics of coal and nuclear power plants in the United States, while the economics of gas plants have been adversely affected by capacity additions that exceed the rate of demand growth. The combination of low gas prices and oversupplied power markets has resulted in declining wholesale power prices in the United States; however, retail and industrial power prices have not fallen. The costs of integrating wind and solar into the grid as well as other factors generally have offset the benefit of lower wholesale prices.

Wind and solar projects have been receiving federal tax subsidies, which are being phased out. Both continue to benefit from Renewable Portfolio Standards (RPS) in many states, which require that a certain percentage of a utility's generation mix be sourced from wind, solar, and other renewable technologies. The economics of wind and solar power are location-specific. A windy site far from a population center may require the building of transmission lines to the load center. Permitting construction of these lines, or windy sites near population centers, is often slow and unpopular with affected communities. Not as well understood is that wind and solar plants require lots of resources to manufacture and build per unit of capacity. Material usage is high because these are not dense sources of energy.

In addition, since wind and solar are intermittent sources of energy, the grid requires more dependable (non-intermittent) sources of power such as coal, nuclear, and natural gas plants that can provide back-up when the wind doesn't blow or the sun doesn't shine. Energy storage is being promoted in some states as a potential solution to the problem of intermittency, and utilities have committed to several significant projects. The cost of batteries has fallen, although they are still expensive and the costs rise the longer you need the battery to be available. Prices of wind turbines and solar panels also have fallen. The phase-out of tax subsidies is putting downward pressure on wind turbine prices. Excess capacity for solar panels manufactured in places like China has driven down costs. At the same time, the costs of natural gas plants and fossil fuels have continued to fall dramatically.

In analyzing the cost of integrating wind and solar power on a grid, you need to include the costs of intermittency. Adding intermittent resources to a grid increases the costs incurred by the grid to support the intermittent power. For example, combined-cycle gas turbine (CCGT) plants may have to cycle more frequently than they are designed to, incurring additional maintenance expense and operating less efficiently in terms of heat rate. You also have to look at the marginal economic value of intermittent resources as well as their costs. As you increase the percentage of resources that are intermittent, you not only increase costs to the grid but you also decrease the value of the incremental power produced. In Texas, for example, on a windy day you might have 50% of the power on the grid coming from wind plants. On a hot day in August with little wind, you might have very little power generated by non-coastal wind. The first, say, 10% of the generation coming on and off at roughly the same time has one value, but if you generate three or four times that amount in the same number of hours, the power you are generating has less value. You are adding supply in the same hours rather than as needed, when needed, and where needed. (For an analysis of this topic, you can read Lion Hirth's paper: "The Economics of Wind and Solar Variability: How the Variability of Wind and Solar Power Affects their Marginal Value, Optimal Deployment, and Integration Costs," November 2014.)

As the United States has added wind and solar to the power grids, and as utilities have made additional investments in transmission and distribution to support these resources, the gap between declining wholesale power and gas prices and the prices charged to retail and industrial customers has grown. We think this presents an opportunity to work with industrial customers at our existing plants and potentially with new customers to lower power costs for them through "inside the fence" projects such as combined heat and power (CHP) facilities.

Today, the amount of capacity being added to the grid exceeds the low growth in demand. These capacity additions to an already oversupplied market are occurring despite low power prices. About half of these additions are wind and solar, driven by state RPS and tax benefits. Low interest rates, lots of available capital, and low heat rates for new gas turbines (the lower the heat rate, the less natural gas needed to generate the same amount of electricity) have been significant factors driving gas plant additions. One analysis forecasts that 42,499 MW will be added to the U.S. electric grid in 2018, which is net of 11,573 MW scheduled to retire this year.[3] That represents an approximate 4% net increase in capacity, when demand growth is low to nil.

We can't predict how all this will turn out. The non-utility power generation market is capital-intensive, commodity-priced, and cyclical. The old saying is "The cure for low commodity prices is low commodity prices," as the price signals affect supply and demand. Power generation is an area heavily affected by government regulation and intervention on the one hand, but can be an easy place to deploy large pools of capital on the other hand, so the need for disciplined capital allocation is great.

## ATLANTIC POWER'S POSITION

### Fuel and Market Diversity

We have a diversified fleet of plants: gas, hydro, biomass, and coal. We think that this technological diversity positions us well under various potential scenarios.

Currently, the market appears to be valuing our gas plants for the remaining cash flows under their PPAs, assuming little or no recontracting occurs when the PPAs expire. However, under a scenario in which integration of wind and solar on the grid continues at a high level and the projected economics of batteries prove optimistic, natural gas plants could benefit because they will be required to serve as back-up for intermittent resources. There might even be some pressure to provide capacity payments for non-intermittent sources of power. Our gas plants are likely beneficiaries in such a scenario.

Our management team has experience with energy storage, and we are exploring potential opportunities around our existing plants, but the economics of batteries are not currently compelling for wholesale applications for extended periods.

Alternatively, we might see the increase in wind and solar power muted by increasing NIMBY (not in my backyard) concerns in communities targeted for development. Having tried to permit two wind projects in the Green Mountain state earlier in our careers, we are more skeptical than most about the ability to achieve very high levels of wind and solar capacity given the land use and permitting issues. Under a scenario where growth in renewables slows, natural gas plants should benefit.

Several of our gas and hydro plants are in locations where it is challenging to site and build new capacity because of NIMBY opposition. That improves the prospects for these plants, where we are in a position to retain control of the site. In areas where the supply and demand outlook is currently unfavorable, such as Ontario, we have preserved our options by mothballing plants rather than dismantling them, in order to have the ability to restart them in a few years should market conditions improve.

Any scenario that results in an increase in electric demand, such as a move to electric vehicles, should be positive, including for conventional power producers.

**PPAs, Cash Flow and Delevering**

Our PPAs have an average remaining term of slightly less than seven years. If power prices remain low or decline further, then as our PPAs roll off, the price we receive for the power should be materially below current contract levels. In developing our estimates of intrinsic value, we assume that market prices will remain in the range of the levels of the past three years, so we expect lower EBITDA from these projects post-PPA. The market views the declining EBITDA as a negative. So do we, but the above-market revenues currently accruing under the PPAs are an asset, resulting in cash flows that are being used to pay down debt significantly, among other uses. As we have indicated on our quarterly conference calls, if we allocate the vast majority of our operating cash flow to debt repayment, by about 2025 we can be approximately net debt-free. In an environment such as we have described, EBITDA could decline from current levels by maybe $100 million during this period, but we'd have a residual business that, while smaller, still generates significant cash flow and carries little or no net debt.

An outcome of "zero" net debt is not our base case, but instead reflects a scenario where power prices stay low for many years and we do not grow. But on a base of no net debt, we'd still own hydro plants with significant long-term value, PPAs at some of our plants running as far out as 2037, and possible option value at some of the other plants for which the PPAs had already expired. We believe the equity value of the Company under that scenario is higher than what the market is currently ascribing.

More likely, though, we will have opportunities prior to 2025 that could be preferable to continued delevering. Seven years is a long time in markets that historically have been volatile. We would attempt to use any intervening price volatility to hedge our assets, to extend PPAs or to bring plants back on line to firm up or grow the back-end EBITDA. We might look to sell assets in that environment. Conversely, if markets become distressed, we might redirect discretionary cash flow into asset purchases. If things are pretty flat, then we might look to add a reasonable amount of debt, rather than getting to a zero net debt level, and use the proceeds to repurchase shares via a tender offer. When we look at the business, then, we think we can extract enough cash flow in a low power price environment to further strengthen our balance sheet, and the progress we have made to date positions us to take advantage of any compelling opportunities the market may present as either a buyer or a seller.

**GROWTH**

We don't see compelling investment opportunities in the power sector today. The psychological bias in favor of growth is strong, so we need to be disciplined. We are value investors. Bruce Greenwald once told me: When there is nothing to do, you have to be willing to do nothing. Internally, I talk about the willingness of Warren Buffett and Charlie Munger to stop underwriting insurance when returns are too low and to move with speed and scale when opportunities emerge. We want to follow that model.

Looking at the investing landscape broadly, we see high valuations implying muted returns in the future. If interest rates returned to the levels of pre-2008, that would create major downward pressure on asset values. Several years ago, James Montier of GMO wrote a paper on financial repression and the implications for value investing.[4] His analysis showed that periods of financial repression can last decades. If we have a reversion to the mean (materially higher interest rates) soon, then the best asset class today is cash. If it takes a decade or two for rates to revert to the mean, then fixed income is probably better than cash, and U.S. equities are probably better than fixed income.

Meanwhile, equity investments in power projects are the rough equivalent of high-yield bonds. Typically a non-utility generation investment is based on an Internal Rate of Return (IRR) calculation derived from a 20- to 30-year pro forma financial model. In the past, the typical structure was to sell the power output to a utility or industrial customer under a PPA, which usually had limited upside if power prices increased, thereby making the investment bond-like in my estimation. If costs increased, there was risk to the downside. Over the last 20 years or so, we have had opportunities to invest in power projects with equity returns in the mid-teens, which seems reasonable. That represented roughly a 5% spread versus a utility's allowed equity rate of return. A utility investment goes into rate base. If the project experiences cost overruns, demand shortfalls or unforeseen issues, the utility owner can seek rate relief. There is no such recourse for non-regulated generation investments.

More recently the YieldCo model was popular on Wall Street. In 2015, I read one YieldCo investor presentation in which they estimated their weighted average cost of capital at 7%, they estimated returns from their investments at 9% and they projected a 15% annual growth rate. I was asked: "Why don't we become a YieldCo?" My answer was that I didn't believe the 7%, the 9% or the 15%. Instead, we sold our wind plants for $350 million (plus project debt, assumed by the buyer) and used the proceeds to pay off $311 million of our remaining 9% senior unsecured notes that we had issued previously to fund growth and which were costing us $28 million annually in interest payments. The moral of the story is that when the markets are doing things that don't make sense to you, sometimes it is better to sell rather than following the crowd.

We don't like the supply and demand fundamentals in this market. Given this view, M&A markets seem high-priced. Power projects are capital-intensive investments that require an adequate margin of safety. When the market starts to accept low returns, the end results are usually poor.

Wind and solar projects are being done at returns that are estimated to be in the single digits. I think power project investments are too risky to accept single-digit returns. We have no more wind or solar plants to sell, or we would be an aggressive seller of those assets today as well. Until the recent tax legislation, about two-thirds of the economics of those projects were derived from tax benefits. We have about $583 million of net operating losses, so we have little appetite for projects driven primarily by tax benefits. Looking back over the past 17 years in wind investing, it seems to me that the tax equity investors as a group have done well but the cash investors as a group have not done well, absent flipping assets. Buy-and-hold cash investors have suffered the consequences of lower-than-expected wind production versus forecasts, something that tax equity investors were structurally well protected from. As a Company, we have invested in wind in the past, and management has invested in both wind and solar at other companies. At the right return levels we are enthusiastic buyers of or investors in wind and solar projects. Not today. For institutions with tax appetites, the picture is different.

We continue to look broadly for external growth opportunities, particularly those that may arise from special situations, such as turning around a challenged asset. We look at biomass projects where we think our operations team can increase the plant's cash flows. We look at contracted coal plants. We look at opportunities to build new projects for industrial customers (CHP projects, generally). We have reviewed the retail electric sector, as have other IPPs. We are generally not willing to invest in merchant plants (plants with no long-term contracts for the output), because that would require us to bet on higher power prices in the future.

This is an opportunistic search process. There are times when we see a multi-year prospect for investing in one asset class, such as we did in wind in 2001 – 2008 when returns were much higher than those available today. Then there are times when the obvious thing to do at the market clearing price is to sell, as we did with our wind portfolio in 2015.

Our experience has been that market sentiment in power can shift dramatically and rapidly, so having dry powder is a good thing. We have approximately $205 million in liquidity, including $122 million of unused revolver capacity and $83 million of unrestricted cash. We can use the revolver to make investments or acquisitions but not to repurchase common or preferred shares. Approximately $32 million of the cash is at the parent and available for discretionary purposes.

Given the external investment environment that I have just described, we have focused instead on internal investments. Over a four-year period, we made $25 million of discretionary optimization investments in our own fleet, which we estimated to have cash returns of 20% and higher, although at this point these investment opportunities are effectively exhausted.

In addition, we continue to see compelling returns from repurchasing our equity securities. Since December 2015, we have purchased $27 million of our common shares and $7 million (U.S. dollar equivalent) of our preferred shares. We bought the preferred shares at a considerable discount to par, and our cash returns from the avoided dividends and related taxes were approximately 10% – 11%. The return on buying back common shares is tougher to analyze. It is more like an IRR analysis for a power plant project than straightforward cash return analysis for discretionary investments in our plants or repurchases of preferred shares. Given the discount of the common share price to our estimates of intrinsic value, we have bought much more common equity than preferred.

Power prices will have a major impact on the long-term value of our business. They will drive asset values. We are fairly agnostic on strategic outcomes in the industry. We are happy to invest in wind, solar, gas, biomass, coal, or storage if the economics are compelling. At present, we don't see good opportunities to deploy our cash externally but that is likely to change over time. In the meantime, we are seeing good returns on our internal uses of capital.

**CAPITAL ALLOCATION**

Given the current power market landscape, you can see why over the past three years we have:

- Reduced debt by more than $900 million;
- Reduced our leverage ratio to 3.3 times from 6.9 times;
- Reduced corporate overheads by slightly more than half; and
- Allocated capital to purchasing $27 million of common shares and $7 million (U.S. dollar equivalent) of preferred shares at what we estimate to be double-digit returns.

We often hear the saying "You can't shrink to greatness," but when our estimate of intrinsic value per share exceeds the share price by a significant amount, we are willing to buy shares. At a stock price higher than our intrinsic value estimate, we would not buy shares. If we can earn better returns investing externally, then we will do that. We are not primarily motivated by growth in the absolute size of the business. We will try to maximize the discounted cash flows of our business on a per-share basis in a declining power price environment by focusing on costs, reducing debt, and buying shares if that is the best use of cash for our shareholders.

In the past, members of the management team have been involved in making billions of dollars of investments in the power sector. We love doing deals, but we insist on having an adequate margin of safety and an expected return better than we can exact out of our own business. Our sole focus is to be as rational as possible in allocating capital for ourselves and our fellow owners of the business. We want to maximize the benefit to the shareholders of a declining business and redirect our capital only when the benefits of external growth are obvious.

**QUESTIONS**

Let me conclude this letter by addressing a few questions that we are frequently asked by shareholders:

**Why not pay a cash dividend?**

Given the business and industry profile laid out above, we don't think dividends make sense. A cash dividend paid out quarterly implies a fair level of confidence in maintaining that dividend. In a volatile, capital-intensive, cyclical business prone to presenting market opportunities to be a buyer or a seller, we think we ought to focus on intrinsic value per share rather than quarterly dividend payments. Investors looking for steady income have better opportunities elsewhere. Also, our shares are well below our estimate of intrinsic value per share, and they have been for the last several years. Buying them in ought to accrete value to remaining shareholders if our estimates are roughly correct. We have no expectation of reinstating a cash dividend anytime in the foreseeable future.

**What can you do about the share price?**

Our approach is to focus on protecting and, if possible, growing the intrinsic value per share of the business. We try not to promote the shares. We view the market quotation as an invitation to buy (as we have been doing, with $31 million of Company and insider purchases) or to sell shares. We try to provide investors as much information as we can, but to make an estimate of value you must have a view of what power prices will be in five, seven, or ten years.

We have made enormous improvements in the business. The share price has not reflected those improvements. Although we are not focused on moving the share price over short time periods, we believe it would be better if our shares traded closer to intrinsic value.

Things that might narrow the valuation gap over time include higher power prices, growth, or significant share repurchases. Higher power prices would drive better post-PPA outcomes for us. Such an environment might rerate the sector, including our shares.

Growth, organic or external, is highly unlikely to totally offset the expected decline in EBITDA from current levels to post-PPA pricing as the decline is too large. As noted earlier, our debt should decline faster than EBITDA if we continue aggressive debt repayment, resulting in declining leverage ratios in 2019 and beyond. At that point the lower leverage may rerate the shares.

In either case (higher power prices or growth), if we continue to shrink the number of shares outstanding, the value of the Company on a per-share basis should grow. We will remain focused on improving the value of the business and we believe that at some point the public market will reflect that value, or a buyer will emerge for the Company.

**Is Atlantic Power too small?**

We don't think so. Our enterprise value is approximately $1.2 billion. The market value of the common equity is approximately $245 million at recent prices. We have $205 million of liquidity. We think of ourselves as akin to a deep value small cap equity investor. Today, there is nothing to get excited about, but at our size investments that are too small for others can move the needle for us. If we had a few billion dollars to invest, there isn't anything we'd want to do with it in the power sector today anyhow.

We look forward to meeting those shareholders who can attend our Annual General Meeting this year, which will be held at the King Edward Hotel in Toronto on June 19, beginning at 10:00 a.m.

James J. Moore, Jr.
*President and Chief Executive Officer*
April 27, 2018

## 2017 Business and Financial Highlights

### Cultural

- *Environmental, health and safety performance.* We had one lost-time incident in 2017 as compared to two in 2016. Our lost-time incident rate improved to 0.38 from 0.69. Although we had three recordable injuries in 2017 (all relatively minor) as compared to two in 2016, our total recordable injury rate of 1.16 was better than our performance in 2014 and 2015. Three of our plants—Kenilworth, Manchief and Piedmont—completed five years of operation without a lost-time incident. We had no notices of violation in 2017 from either the Federal Energy Regulatory Commission or the North American Electric Reliability Council. Our Kenilworth plant received an Environmental Stewardship Certificate from the New Jersey Department of Environmental Protection for its voluntary and proactive measures to improve the environment and ensure a sustainable future.
- *Servant leadership.* We continued to focus on promoting a culture of servant leadership throughout the Company. In 2017, we continued to roll out training throughout the organization. All members of senior management and all plant managers have now participated in the training.

### Operational

- *Availability.* Our plants had an availability factor of 90.3%, which was a strong performance although modestly lower than the 93.3% availability recorded in 2016, due to planned outages in 2017 at our Frederickson and Kenilworth plants and forced outages at our Mamquam and Williams Lake plants.
- *Maintenance and optimization initiatives.* We upgraded the third of the three gas turbines at our Morris plant. This completed a major undertaking at the Morris plant begun in 2016 to increase output and improve efficiency of the gas turbines and add fast-start capability to the second of two auxiliary boilers. We also replaced the control system at our Cadillac plant and upgraded the gas turbine at our equity-owned Frederickson plant.
- *Launched plant cost savings initiative.* In late 2016, we began a program to analyze and benchmark our plant operating costs with a goal of achieving cost savings. In 2017, we completed the internal benchmarking effort and held both operations and maintenance summits for our plant employees to identify and implement best practices, with a focus on outage frequency and maintenance intervals. We have implemented $2 million of non-fuel permanent cost reductions for 2018 and eliminated $2 million of planned maintenance spending from future years. We also reduced our overall fleet fuel usage (on a load-adjusted basis) by approximately 3% in 2017, resulting in fuel cost savings of approximately $3 million. In addition, we deployed Predictive Analytic maintenance software (PRISM) at three plants and expect to deploy it at another three sites this year. This software should improve reliability and operational performance.

### Commercial

- *Revised contract for Nipigon.* We negotiated a new long-term enhanced dispatch contract for our Nipigon plant for the period November 2018 through December 2022. Under the revised contract, the Nipigon plant will return to service in November 2018 as a simple-cycle plant and will operate on a flexible basis. The new contract reduces the operating risk of the plant and results in improved economic outcomes for the plant as well as Ontario ratepayers as compared to the original PPA.

- *Amended PPA for our Tunis plant.* We reached agreement with the customer on amendments to the Tunis PPA that provide for the plant to operate in simple-cycle mode, which we expect will result in a lower risk profile. We also were successful in obtaining an amended permit for the plant. We commenced work on returning the plant to service in late 2017 and expect it to return to operation under the 15-year PPA in the third quarter of 2018.
- *Short-term contract extension for our Williams Lake plant.* We amended and extended our existing contract with BC Hydro for our Williams Lake plant by approximately 15 months, or 18 months at the option of BC Hydro. Although the economic contribution during the extension is expected to be *de minimis*, the purpose of the extension is to bridge operations of the plant to a possible longer-term extension of the contract, depending on the outcome of BC Hydro's Integrated Resource Plan in the second or third quarter of 2019.
- *Executed new contracts for the three San Diego plants, although have not achieved site control.* We signed new seven-year contracts for our Naval Station and North Island plants with San Diego Gas & Electric and for our Naval Training Center plant with Southern California Edison, but have not succeeded in obtaining site control with the U.S. Navy, which is required for us to restart operations at the plants.
- *Amended existing PPAs for the three San Diego plants.* The amendment provides for early termination of the PPAs without any potential liabilities to the customer. The amendments were approved by the California Public Utilities Commission in March 2018.
- *Negotiated final adjustments to OEFC Settlement.* These efforts resulted in an additional Cdn$1.7 million of revenue received under the Global Adjustment settlement with the Ontario Electricity Financial Corporation, bringing the total to Cdn$37.8 million.

**Financial**

- *Strong financial results.* For 2017, Cash provided by operating activities (a GAAP measure) was $169 million, which was in the upper half of our estimated range of $160 million to $175 million. Project Adjusted EBITDA was $289 million, which exceeded our guidance range of $260 million to $275 million. Both guidance ranges were revised upward twice during 2017.
- *Debt reduction.* We repaid $166 million of debt in 2017, reducing our leverage ratio at year-end to 3.3 times.
- *Two successful re-pricings of our term loan.* In April 2017 and again in October 2017, we successfully re-priced the spread on our term loan and revolver by a total of 150 basis points, to LIBOR plus 350 basis points. The combined savings of both re-pricing transactions is estimated to be approximately $33 million over the remaining terms of the facilities.
- *Improved debt maturity profile.* By repaying the Piedmont project debt in full, we eliminated our only 2018 bullet maturity. In October 2017, we extended the maturity date of our $200 million corporate revolver by one year, to April 2022, which ensures a stable liquidity profile during this period.
- *Strong liquidity.* Our liquidity at year-end 2017 was $198 million, including approximately $40 million of discretionary cash, after allocating approximately $71 million of liquidity to the Piedmont debt repayment in October 2017.
- *Improved credit profile.* In October 2017, Moody's upgraded our corporate family credit rating to Ba3 from B1, representing the second upgrade from Moody's in a two-year period.
- *Stable overhead costs.* Corporate general and administrative (G&A) costs for 2017 of $22 million were approximately $0.6 million lower than in 2016. Although the most significant cost

reductions are behind us, we continue to look for additional cost reduction opportunities. In 2017, we eliminated seven positions for estimated savings of $1.2 million annually and absorbed this work within existing teams. We also further reduced our property and casualty insurance costs modestly.

**Capital Allocation**

- *Piedmont debt repayment.* After considering an asset sale and refinancing options for the plant's August 2018 debt maturity, we elected to allocate a portion of our liquidity to repayment of the $54.6 million project debt. This improved our maturity profile by eliminating our only 2018 bullet maturity. It also results in $4.4 million of annual interest cost savings and allowed the project to make cash distributions to the parent for the first time. Piedmont generates Project Adjusted EBITDA of approximately $9 million to $10 million annually and has a PPA with an investment-grade customer that runs through 2032, which will help to support our long-term cash flows. We considered this debt repayment to be an excellent use of our discretionary capital.

- *Repurchases of preferred and common shares.* During 2017, we repurchased 250,000 preferred shares and 93,391 common shares, at a total investment of approximately $3.3 million (U.S. dollar equivalent). We consider the returns on these investments to be more compelling than the returns available in the current power market environment.

**Notes**

[1] Leverage ratio is defined as the ratio of Consolidated Debt to Adjusted EBITDA, calculated for the trailing four quarters. Note that we calculate this ratio on a gross debt basis, not net of cash.

[2] Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP, and is therefore unlikely to be comparable to similar measures presented by other companies. Investors are cautioned that the Company may calculate this non-GAAP measure in a manner that is different from other companies. The most directly comparable GAAP measure is Project income (loss). Project Adjusted EBITDA is defined as Project income (loss) plus interest, taxes, depreciation, and amortization (including non-cash impairment charges), and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net loss on a consolidated basis is provided in Annex A on page xvi.

[3] Cotting, Ashleigh. "U.S. grid expected to add a net 42,500 MW of capacity in 2018." S&P Global Market Intelligence, January 30, 2018.

[4] Montier, James. "The 13th Labour of Hercules: Capital Preservation in the Age of Financial Repression." GMO white paper, November 29, 2012.

**Cautionary Note Regarding Forward-Looking Statements**

To the extent any statements made in this letter contain information that is not historical, these statements are forward-looking statements within the meaning of Section 27A of the U.S. Securities Act of 1933, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended, and under Canadian securities law (collectively, "forward-looking statements").

Certain statements in this letter may constitute "forward-looking statements", which reflect the expectations of management regarding the future growth, results of operations, performance and business prospects and opportunities of the Company and its projects. These statements, which are based on certain assumptions and describe the Company's future plans, strategies and expectations, can generally be identified by the use of the words "may," "will," "project," "continue," "believe," "intend," "anticipate," "expect" or similar expressions that are predictions of or indicate future events or trends and which do not relate solely to present or historical matters. Examples of such statements in this letter include, but are not limited, to statements with respect to the following:

- the Company's plan to repay another $100 million of debt in 2018;
- the Company's expectation that its leverage ratio will increase to the high 4 times range by year-end 2018 because of lower expected Project Adjusted EBITDA;
- the Company's expectation that its leverage ratio will begin to decline again in 2019 and beyond;
- the Company's expectation that it will amortize approximately $470 million of term loan and project debt from 2018 through 2022;
- the Company's estimate that its interest payments will decline to approximately $45 million in 2018, which is $27 million below the 2017 level;
- the Company's expectation that it will return the Nipigon plant to service in November 2018;
- the Company's estimate that its optimization investments produced a cumulative cash return of approximately $32 million in 2013 through 2017, and should produce a recurring cash return of approximately $11 million to $12 million annually in 2018 and beyond;
- the Company's expectations with respect to the level of Project Adjusted EBITDA and operating cash flow in 2018;
- the Company's estimate that the impact of PPA expirations and extensions and the non-recurrence of the OEFC Settlement will reduce 2018 Project Adjusted EBITDA by approximately $105 million relative to 2017;
- the Company's view that the fuel diversity of its plants positions it well under various potential scenarios;
- the Company's expectations with respect to future levels of Project Adjusted EBITDA following the expiration of its PPAs;
- the Company's estimate that it should have net debt of approximately zero by about 2025, assuming planned levels of debt repayment;
- the Company's view of the equity value of the Company under a low power price and significant debt repayment scenario;
- the Company's view that returns from repurchasing its equity securities are compelling, and that its shares are trading well below its estimates of intrinsic value; and
- the Company's indication that it has no expectation of reinstating a cash dividend in the foreseeable future.

Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. Please refer to the factors discussed under “Risk Factors” and “Forward-Looking Information” in the Company’s periodic reports as filed with the U.S. Securities and Exchange Commission (the “SEC”) from time to time for a detailed discussion of the risks and uncertainties affecting the Company. Although the forward-looking statements contained in this news release are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. These forward-looking statements are made as of the date of this letter and, except as expressly required by applicable law, the Company assumes no obligation to update or revise them to reflect new events or circumstances.

## ATLANTIC POWER CORPORATION

## RECONCILIATION OF NET LOSS (A GAAP MEASURE) TO PROJECT ADJUSTED EBITDA FOR THE YEARS ENDED DECEMBER 31, 2017 AND DECEMBER 31, 2016 (UNAUDITED)
**(in millions of U.S. dollars, except as otherwise stated)**

| | 2017 | 2016 |
|---|---|---|
| **Net loss attributable to Atlantic Power Corporation** | **($ 98.6)** | **($122.4)** |
| Net income attributable to preferred share dividends of a subsidiary company | 5.6 | 8.5 |
| **Net loss** | **($ 93.0)** | **($113.9)** |
| Income tax benefit | (58.1) | (14.6) |
| Loss from operations before income taxes | (151.1) | (128.5) |
| Administration | 23.6 | 22.6 |
| Interest expense, net | 64.2 | 106.0 |
| Foreign exchange loss | 16.3 | 13.9 |
| Other income, net | (0.4) | (3.9) |
| **Project (loss) income** | **($ 47.4)** | **$ 10.1** |
| **Reconciliation to Project Adjusted EBITDA** | | |
| Depreciation and amortization | $ 133.2 | $ 133.5 |
| Interest expense, net | 19.2 | 10.9 |
| Change in the fair value of derivative instruments | (2.1) | (37.9) |
| Other income, net | (1.2) | (0.3) |
| Impairment | 187.1 | 85.9 |
| **Project Adjusted EBITDA** | **$ 288.8** | **$ 202.2** |

AtlanticPower Corporation

FOLLOWING IS THE COMPANY'S ANNUAL REPORT ON FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2017

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# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**WASHINGTON, D.C. 20549**

# FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2017**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from to**

**Commission file number 001-34691**

# ATLANTIC POWER CORPORATION
(Exact Name of Registrant as Specified in its Charter)

| | |
|---|---|
| **British Columbia, Canada** | **55-0886410** |
| (State of Incorporation) | (I.R.S. Employer Identification No.) |
| **3 Allied Drive, Suite 220**<br>**Dedham, MA** | **02026** |
| (Address of Principal Executive Offices) | (Zip Code) |

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

Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Shares, no par value per share, and the associated Rights to Purchase Common Shares | The New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

| | | | |
|---|---|---|---|
| Large Accelerated Filer ☐ | Accelerated Filer ☒ | Non-Accelerated Filer ☐<br>(Do not check if a smaller reporting company) | Smaller reporting company ☐ |

Emerging growth company ☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

As of June 30, 2017, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was $271.9 million based upon the last reported sale price on the New York Stock Exchange. For purposes of the foregoing calculation only, all directors and executive officers of the registrant have been deemed affiliates.

As of February 27, 2018, 116,008,834 of the registrant's Common Shares were outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's definitive Proxy Statement for its 2018 Annual Meeting of Shareholders, to be filed not later than 120 days after the end of the registrant's fiscal year, are incorporated by reference into Items 10 through 14 of Part III of this Annual Report on Form 10-K.

## TABLE OF CONTENTS

## PART I

As used herein, the terms "Atlantic Power," the "Company," "we," "our," and "us" refer to Atlantic Power Corporation, together with those entities owned or controlled by Atlantic Power Corporation, unless the context indicates otherwise. All references to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$," "US$" and "U.S. dollars" are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements in this Annual Report on Form 10-K constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995 and Canadian securities laws. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "outlook," "objective," "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "should," "plans," "continue," or similar expressions suggesting future outcomes or events. Examples of such statements in this Annual Report on Form 10-K include, but are not limited to, statements with respect to the following:

- our ability to generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities;
- the outcome or impact of our business strategy to increase our intrinsic value on a per-share basis through disciplined management of our balance sheet and cost structure and investment of our discretionary cash in a combination of organic and external growth projects, acquisitions, and repurchases of debt and equity securities;
- our ability to renew or enter into new power purchase agreements ("PPAs") on favorable terms or at all after the expiration of our current agreements;
- our ability to meet the financial covenants under our Credit Facilities (as defined herein) and other indebtedness;
- expectations regarding maintenance and capital expenditures; and
- the impact of legislative, regulatory, competitive and technological changes.

Such forward-looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this Annual Report on Form 10-K. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward-looking statement made by us or on our behalf.

Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under "Item 1A. Risk Factors" in this Annual Report on Form 10-K. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- the expiration or termination of power purchase agreements ("PPAs") and our ability to renew or enter into new PPAs on favorable terms or at all;

- our ability to service our debt obligations or generate sufficient cash flow to pay preferred dividends;
- our ability to access liquidity for the ongoing operation of our business and the execution of our business plan or any potential options, which may involve one or more of the use of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately-placed bank or institutional non-recourse operating level debt;
- our indebtedness and financing arrangements and the terms, covenants and restrictions included in our Credit Facilities;
- exchange rate fluctuations;
- the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;
- unstable capital and credit markets;
- the dependence of our projects on their electricity and thermal energy customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;
- the dependence of our projects on third-party suppliers;
- projects not operating according to plan;
- the effects of weather, which affects demand for electricity and fuel as well as operating conditions;
- U.S., Canadian and/or global economic conditions and uncertainty;
- risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;
- the adequacy of our insurance coverage;
- the impact of significant energy, environmental and other regulations on our projects;
- the impact of impairment of goodwill, long-lived assets or equity method investments;
- the impact of failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002;
- increased competition, including for acquisitions;
- our limited control over the operation of certain minority-owned projects;
- transfer restrictions on our equity interests in certain projects;
- risks inherent in the use of derivative instruments;
- labor disruptions;
- the impact of hostile cyber intrusions;

- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and

- our ability to retain, motivate and recruit executives and other key employees.

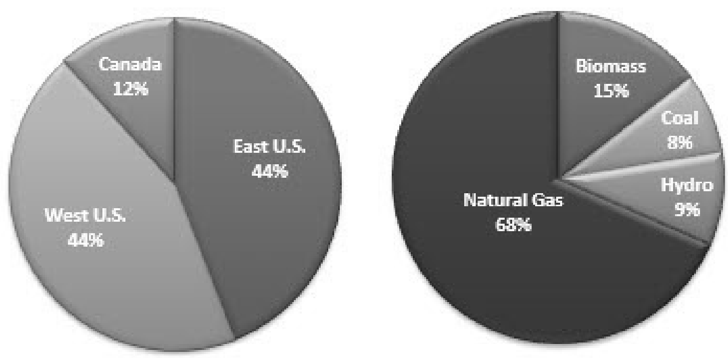
Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include, without limitation, third-party projections of regional fuel and electric capacity and energy prices based on assumptions about future economic conditions and courses of action, the general conditions of the markets in which the Company operates, revenues, internal and external growth opportunities, the Company's ability to sell assets at favorable prices or at all and general financial market and interest rate conditions. Although the forward-looking statements contained in this Annual Report on Form 10-K are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Annual Report on Form 10-K may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Annual Report on Form 10-K. These forward-looking statements are made as of the date of this Annual Report on Form 10-K and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

## ITEM 1. BUSINESS

## GENERAL

Atlantic Power is an independent power producer that owns power generation assets in nine states in the United States and two provinces in Canada. Our power generation projects, which are diversified by geography, fuel type, dispatch profile and offtaker, sell electricity to utilities and other large customers predominantly under long-term PPAs, which seek to minimize exposure to changes in commodity prices. As of December 31, 2017, the Company's portfolio consisted of twenty-two projects with an aggregate electric generating capacity of approximately 1,793 megawatts ("MW") on a gross ownership basis and approximately 1,440 MW on a net ownership basis. Eighteen of the projects are majority-owned and operated by the Company. Four of the Company's projects in Ontario are not in operation, two because of contract expirations at December 31, 2017, another due to a revised contractual arrangement with the offtaker, and the fourth, Tunis, has a forward-starting 15-year contractual agreement that will commence with commercial operation of the plant during the third quarter of 2018. The eighteen projects in operation at December 31, 2017 have generating capacity of approximately 1,633 MW on a gross ownership basis and approximately 1,280 MW on a net ownership basis. In early February 2018, the Company's three plants in San Diego, totaling 112 MW on a gross and net ownership basis, ceased operations, as discussed in Our Organization and Segments.

The following charts show, based on generation capacity in MW, the diversification of our portfolio by segment and fuel type for our projects currently in operation:




We sell the majority of the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from September 30, 2018 to December 31, 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

The majority of our natural gas, coal and biomass power generation projects have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is no pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies.

We directly operate and maintain the majority of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Heorot Power Management LLC ("Heorot") and Purenergy LLC ("Purenergy"). Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

## HISTORY OF OUR COMPANY

Atlantic Power Corporation is a corporation continued under the laws of British Columbia, Canada, which was incorporated in 2004. We used the proceeds from our initial public offering on the Toronto Stock Exchange ("TSX") in November 2004 to acquire a 58% interest in Atlantic Power Holdings, LLC (which we refer to herein as "Atlantic Holdings") from two private equity funds managed by ArcLight Capital Partners, LLC ("ArcLight") and from Caithness Energy, LLC ("Caithness"). Until December 31, 2009, we were externally managed under an agreement with Atlantic Power Management, LLC, an affiliate of ArcLight, when we agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement with us. In connection with the termination of the management agreement, we hired all of the then-current employees of Atlantic Power Management and entered into employment agreements with its three officers.

At the time of our initial public offering, our publicly traded security was an Income Participating Security ("IPS"), which was comprised of one common share and a subordinated note. In November 2009, our shareholders approved a conversion from the IPS structure to a traditional common share structure in which each IPS was exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share. Our common shares trade on the TSX under the symbol "ATP". On July 23, 2010, we also began trading on the New York Stock Exchange ("NYSE") under the symbol "AT".

On November 5, 2011, we directly and indirectly acquired all of the issued and outstanding limited partnership units of Capital Power Income L.P., which was renamed Atlantic Power Limited Partnership on February 1, 2012 (the "Partnership"). The Partnership's portfolio consisted of 19 wholly-owned power generation assets located in both Canada and the United States, a 50.15% interest in a power generation asset in the state of Washington, and a 14.3% common ownership interest in Primary Energy Recycling Holdings, LLC which was later sold in 2012. At the acquisition date, the transaction increased the net generating capacity of our projects by 143% from 871 MW to approximately 2,116 MW.

On June 26, 2015, we sold our 100% ownership interest in Meadow Creek Project Company, LLC ("Meadow Creek"), 99% ownership in Canadian Hills Wind, LLC ("Canadian Hills"), 50% ownership interest in Rockland Wind Farm, LLC ("Rockland"), 27.6% ownership interest in Idaho Wind Partners 1, LLC ("Idaho Wind") and 12.5% ownership interest in Goshen Phase II, LLC ("Goshen") (collectively, the "Wind Projects"), totaling 521 MW net ownership to TerraForm AP Acquisition Holdings, LLC ("TerraForm"), an affiliate of SunEdison, Inc.

## OUR BUSINESS STRATEGY

### General

Our business strategy is to increase the intrinsic value of the Company on a per-share basis through disciplined management of our balance sheet and our cost structure and investment of our discretionary cash in a combination of organic and external growth projects, acquisitions, and repurchases of our debt and equity securities. In evaluating these potential investments we are guided by the price-to-value relationship. With respect to organic growth, we have been making optimization investments in our existing projects that have produced cash returns higher than those currently available externally. We may undertake additional investments to repower certain facilities in conjunction with extensions of existing PPAs. We evaluate external growth opportunities on a regular basis, and have a highly disciplined and opportunistic approach. We will use discretionary cash for repurchases of our debt and equity securities only when the price-to-value level is compelling, with a goal of increasing intrinsic value per share while also improving the Company's financial flexibility and strengthening its balance sheet. We use our depth of asset management experience to enhance the operating, contractual and financial performance of our current portfolio of projects.

In 2017, we continued to successfully execute our key initiative of improving the balance sheet. We lowered the interest rate on our term loan facilities (the "Term Loan Facilities") twice, decreasing the rate from LIBOR plus 5.00% to LIBOR plus 3.50%. This decrease is expected to save approximately $33 million of interest expense through maturity. We continued to amortize our corporate and project-level debt with approximately $166 million of principal payments. Since embarking on our debt reduction strategy, we have reduced our overall leverage by approximately $1 billion and from 9.5 times EBITDA at 2013 to approximately 3.3 times EBITDA at December 31, 2017. In October 2017, Moody's Investors Service ("Moody's) upgraded our Corporate Family Rating to Ba3 from B1 and the senior secured term loan and revolving credit facilities at APLP Holdings to Ba2 from Ba3.

On January 29, 2018, we closed the sale of our offering (the "Series E Debenture Offering") of Cdn$100 million aggregate principal amount of 6.00% Series E convertible unsecured subordinated debentures (the "Series E Debentures"). We also granted the underwriters the option to purchase up to an additional Cdn$15 million aggregate principal amount of Series E Debentures at any time up to 30 days after the date of closing of the Series E Debenture Offering to cover over-allotments. The underwriters exercised that option for the full Cdn$15 million aggregate principal amount on February 2, 2018.

On the initial closing date, we received net proceeds from the Series E Debentures Offering, after deducting the underwriting fee and expenses, of approximately Cdn$94.7 million. We received an additional Cdn$14.4 million of net proceeds from the exercise of the over-allotment option. On January 29, 2018, we issued a notice to redeem all of the $42.5 million remaining principal amount of 5.75% Series C convertible unsecured subordinated debentures due June 2019 (the "Series C Debentures") with the use of a portion of the proceeds from the Series E Debenture Offering. On February 2, 2018, we issued a notice to redeem Cdn$56.2 million principal amount of the 6.00% Series D extendible convertible unsecured subordinated debentures (the "Series D Debentures") with the remaining proceeds from the Series E Debentures Offering. After the partial redemption, Cdn$24.7 million aggregate principal amount of the Series D Debentures remain outstanding.

**Extending PPAs following their expiration**

PPAs in our portfolio have expiration dates ranging from September 30, 2018 to December 31, 2037. We plan for PPA expirations by evaluating various options in the market. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, approaches by the projects to likely bilateral counterparties, including traditional PPAs, tolling agreements with creditworthy energy trading firms or the use of derivatives to lock in value. The current market for PPAs is challenging. When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements, if any, may be reduced and in some cases, significantly. Our projects may not be able to secure a new agreement and could be exposed to selling power at spot market prices. It is possible that subsequent PPAs or the spot markets may not be available at prices that permit the operation of the project on a profitable basis. For the status of description of some of our PPAs and related renegotiations, see Item 1A. "Risk Factors—Risk Related to Our Business and Our Projects—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition." We do not assume that revenues or operating margins under existing PPAs will necessarily be sustained after PPA expirations, since most original PPAs included capacity payments related to return of and return on original capital invested, and counterparties or evolving regional electricity markets may or may not provide similar payments under new or extended PPAs.

**Organic growth**

We intend to look for opportunities to enhance the operational and financial performance of our projects through:

- achievement of improved operating efficiencies, output, reliability and operation and maintenance costs through the upgrade or enhancement of existing equipment or plant configurations;

- optimization of commercial arrangements such as PPAs, fuel supply and transportation contracts, steam sales agreements, operations and maintenance agreements and hedging arrangements; and

- to the extent we have sufficient cash flow or are able to obtain financing, the expansion or redevelopment of existing projects, or development of new long-term contracted plants with industrial customers.

**Acquisition and investment strategy**

To the extent we pursue acquisitions, we intend to expand our operations by making accretive acquisitions with a focus on power generation facilities in the United States and Canada. We may also work with experienced development companies to acquire additional late stage development projects. There is also a very active secondary market for the purchase and sale of existing projects.

**Development and construction**

We have invested and may invest in the future in energy-related projects primarily in the electric power industry, including investments in late stage development projects or companies where the prospects for creating long-term cash flows are attractive. We may also seek to develop new plant opportunities with other industrial customers. We believe this approach makes sense based on the current structure of the power markets and it is a market segment that is within our core competencies.

## OUR COMPETITIVE STRENGTHS

We have the following competitive strengths:

- ***Diversified projects.*** Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,633 MW, and our net ownership interest in these projects is approximately 1,280 MW at December 31, 2017. These projects are diversified by fuel type, electricity and steam customers, technologies, project operators and geography. The majority are located in the U.S. Eastern, Mid-Atlantic and Midwest regions, and the province of British Columbia.

- ***Experienced management team.*** Our management team has a depth of experience in commercial power operations and maintenance, project development, asset management, mergers and acquisitions, capital raising and management and financial controls.

- ***Stability of project cash flow.*** Many of our power generation projects currently in operation have been in operation for more than ten years. Cash flows from each project are generally supported by PPAs with investment-grade utilities and other creditworthy counterparties. We aim to stabilize operating margins through a combination of a project's PPAs, fuel supply agreements and/or commodity hedges, when possible.

- ***Strong in-house operations and asset management teams.*** We manage the operations of fourteen of our eighteen operating power generation projects, which represent approximately 63% of our portfolio's total net generating capacity. The remaining four generation projects are operated by third parties, which are recognized leaders in the independent power business.

## ASSET MANAGEMENT

Our asset management strategy is to manage our physical assets and commercial relationships to increase shareholder value. We proactively seek scale opportunities and to establish best practices that result in EBITDA and cash flow growth across all of our eighteen operating plants. Our asset management group works to ensure that our projects receive appropriate preventative and corrective maintenance and incur capital expenditures to provide for their safety, efficiency, availability, flexibility, longevity, and growth in EBITDA contribution. We also proactively look for opportunities to optimize power purchase, fuel supply, long-term service and other agreements to deliver strong and predictable financial performance. The teams at each of the businesses have extensive experience in managing, operating and maintaining the assets.

For operations and maintenance services at the four projects in our portfolio which we do not operate, we partner with experienced operators in the independent power business. Examples of our third-party operators include Heorot and Purenergy, which are experienced, well regarded energy infrastructure management services companies. In addition, employees of Atlantic Power with significant experience managing similar assets are involved in all significant decisions with the objective of proactively identifying value-creating opportunities such as contract renewals or restructurings, asset-level refinancings, add-on acquisitions, divestitures and participation at partnership meetings and calls.

**OUR ORGANIZATION AND SEGMENTS**

The following tables outline by segment our portfolio of power generating assets in operation as of December 31, 2017, including our interest in each facility. We believe our portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as a result of significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. These changes reflect our current operating focus. The segment classified as Un-Allocated Corporate includes activities that support the executive and administrative offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss.

The sections below provide descriptions of our projects as they are aligned in our segment reporting structure for financial reporting purposes.

See Note 22 to the consolidated financial statements for information on revenue from external customers, Project Adjusted EBITDA (a non-GAAP measure), total assets by segment and revenue and total assets by geography.

***East U.S. Segment***

Our East U.S. segment accounted for 35.4%, 33.7% and 35.7% of consolidated revenue in 2017, 2016 and 2015, respectively, and total net generation capacity of 531 MW at December 31, 2017. Niagara Mohawk Power Corporation accounted for 11% of total consolidated revenues and 30% of total revenues from the East U.S. segment, respectively, for the year ended December 31, 2017.

The table below provides the revenue and project income for the East U.S. segment. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Project Income (Loss) by Segment for additional details on our project income (loss).

| | East U.S. Segment | |
|---|---|---|
| | Revenue ($ in millions) | Project (loss) income ($ in millions) |
| 2017 | $ 152.5 | $ (17.0) |
| 2016 | 134.5 | 31.2 |
| 2015 | 150.0 | 38.7 |

Set forth below is a list of our East U.S. projects in operation at December 31, 2017:

| Project | Location | Fuel | Gross MW | Economic Interest | Net MW | Primary Electric Purchasers | Power Contract Expiry | Customer Credit Rating (S&P) |
|---|---|---|---|---|---|---|---|---|
| Orlando(1) | Florida | Natural Gas | 129 | 50.00 % | 65 | Progress Energy Florida | December 2023 | A- |
| Piedmont | Georgia | Biomass | 55 | 100.00 % | 55 | Georgia Power | September 2032 | A- |
| Morris | Illinois | Natural Gas | 177 | 100.00 % | 120 | Merchant | N/A | NR |
| | | | | | 57 | Equistar Chemicals, LP(2) | December 2034 | BBB+ |
| Cadillac | Michigan | Biomass | 40 | 100.00 % | 40 | Consumers Energy | June 2028 | BBB |
| Chambers(1) | New Jersey | Coal | 262 | 40.00 % | 89 | Atlantic City Electric (3) | March 2024 | BBB+ |
| | | | | | 16 | Chemours Co. | March 2024 | BB |
| Kenilworth | New Jersey | Natural Gas | 29 | 100.00 % | 29 | Merck & Co., Inc. | September 2018 | AA |
| Curtis Palmer(4) | New York | Hydro | 60 | 100.00 % | 60 | Niagara Mohawk Power Corporation | December 2027 | A- |

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

(2) Represents the credit rating of LyondellBasell, the parent company of Equistar Chemicals, as Equistar is not rated.

(3) The base PPA with Atlantic City Electric ("ACE") makes up the majority of the 89 net MW. For sales of energy and capacity not purchased by ACE under the base PPA and sold to the spot market, profits are shared with ACE under a separate power sales agreement.

(4) The Curtis Palmer PPA expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. From January 6, 1995 through December 31, 2017, the facility has generated 7,329 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

***West U.S. Segment***

Our West U.S. segment accounted for 25.3%, 25.4% and 24.9% of consolidated revenue in 2017, 2016 and 2015, respectively, and total net generation capacity of 592 MW at December 31, 2017. San Diego Gas & Electric accounted for 11% of total consolidated revenues and 41% of total revenues from the West U.S. segment for the year ended December 31, 2017.

The table below provides the revenue and project income (loss) for the West U.S. segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations—Project Income (Loss) by Segment for additional details on our project income (loss).

| | West U.S. Segment | |
|---|---|---|
| | Revenue ($ in millions) | Project (loss) income ($ in millions) |
| 2017 | $ 108.9 | $ (72.0) |
| 2016 | 101.3 | 11.8 |
| 2015 | 104.6 | 38.7 |

Set forth below is a list of our West U.S. projects in operation at December 31, 2017:

| Project | Location | Fuel | Gross MW | Economic Interest | Net MW | Primary Electric Purchasers | Power Contract Expiry | Customer Credit Rating (S&P) |
|---|---|---|---|---|---|---|---|---|
| Naval Station | California | Natural Gas | 47 | 100.00 % | 47 | San Diego Gas & Electric | (1) | A |
| Naval Training Center | California | Natural Gas | 25 | 100.00 % | 25 | San Diego Gas & Electric | (1) | A |
| North Island | California | Natural Gas | 40 | 100.00 % | 40 | San Diego Gas & Electric | (1) | A |
| Oxnard | California | Natural Gas | 49 | 100.00 % | 49 | Southern California Edison | April 2020 | BBB+ |
| Manchief | Colorado | Natural Gas | 300 | 100.00 % | 300 | Public Service Company of Colorado | April 2022 (2) | A- |
| Frederickson(3) | Washington | Natural Gas | 250 | 50.15 % | 50 | Benton Co. PUD | August 2022 | AA- |
| | | | | | 45 | Grays Harbor PUD | August 2022 | A+ |
| | | | | | 30 | Franklin Co. PUD | August 2022 | A+ |
| Koma Kulshan(3) | Washington | Hydro | 13 | 49.80 % | 6 | Puget Sound Energy | December 2037 | BBB |

(1) Our land use license agreements with the U.S. Navy expired on February 7, 2018. Our PPAs with San Diego Gas & Electric terminated on March 1, 2018. We were unable to extend our land use license agreements through the end of our PPAs and ceased operations at these plants on February 7, 2018. See discussion below.

(2) Public Service Company of Colorado has options to purchase Manchief in either May 2020 or May 2021.

(3) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

Recent developments affecting our San Diego projects

Three of our projects (Naval Station, North Island and Naval Training Center) have PPAs with San Diego Gas & Electric that expire in December 2019, although the steam sales agreements with the U.S. Navy for all three projects expired on February 7, 2018. Our right to use the property on which the plants are located (on existing Naval or Marine bases) also expired on February 7, 2018.

In July 2017, we entered into new seven-year Power Purchase Tolling Agreements for the Naval Station and North Island projects. The agreements are with SDG&E and are subject to certain significant conditions including retaining the right to operate on the Navy properties. As of February 28, 2018, we have not obtained the right to operate on the Naval or Marine properties ("site control").

We have also executed amendments to the existing PPAs with SDG&E for Naval Station, North Island and Naval Training Center, which provide for termination of the existing PPAs.

We have also entered into Resource Adequacy ("RA") contracts with SDG&E for all three projects, which are subject to retaining site control beyond February 2018. The RA contracts for Naval Station and North Island are contingent arrangements that would become effective only under limited circumstances and conditions. In addition, we and SDG&E have entered into an RA contract for NTC, under which NTC would supply RA capacity to SDG&E from February through December 2018.

We obtained approval of the California Public Utilities Commission ("CPUC") for the aforementioned Power Purchase Tolling Agreements, termination of the existing PPAs and the RA contracts on March 1, 2018. As a result of the approval, the existing PPAs with SDG&E for Naval Station, North Island and Naval Training Center were terminated on March 1, 2018.

We entered into a seven-year PPA with Southern California Edison for our NTC project commencing in January 2019. The PPA is a sale of RA capacity and a toll of the energy production resulting from offering the resource to the California Independent System Operator. This PPA is subject to obtaining site control and CPUC approval.

Even if we are successful in pursuing a path to site control and receive CPUC approval of the NTC agreement, Project Adjusted EBITDA is expected to be significantly lower than the $21.0 million recorded in 2017 for these three projects.

***Canada Segment***

Our Canada segment accounted for 39.1%, 40.7% and 39.2% of consolidated revenue in 2017, 2016 and 2015, respectively, and total net generation capacity for operational projects of 237 MW at December 31, 2017. Ontario Electric Financial Corporation ("OEFC") and British Columbia Hydro and Power Authority ("BC Hydro") accounted for 20% and 10% of total consolidated revenues, respectively, and 52% and 26% of total revenues from the Canada segment, respectively, for the year ended December 31, 2017.

The table below provides the revenue and project income (loss) for the Canada segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations—Project Income (Loss) by Segment for additional details on our project income (loss).

| | Canada Segment | |
|---|---|---|
| | **Revenue ($ in millions)** | **Project income (loss) ($ in millions)** |
| 2017 | $ 168.6 | $ 38.8 |
| 2016 | 162.5 | (35.7) |
| 2015 | 164.7 | (85.7) |

Set forth below is a list of our Canada projects in operation or under contract at December 31, 2017:

| Project | Location | Fuel | Gross MW | Economic Interest | Net MW | Primary Electric Purchasers | Power Contract Expiry | Customer Credit Rating (S&P) |
|---|---|---|---|---|---|---|---|---|
| Mamquam | British Columbia | Hydro | 50 | 100.00 % | 50 | BC Hydro | September 2027 [1] | AAA |
| Moresby Lake | British Columbia | Hydro | 6 | 100.00 % | 6 | BC Hydro | August 2022 | AAA |
| Williams Lake | British Columbia | Biomass | 66 | 100.00 % | 66 | BC Hydro | June 2019 [2] | AAA |
| Calstock | Ontario | Biomass | 35 | 100.00 % | 35 | OEFC | June 2020 | AA |
| Nipigon | Ontario | Natural Gas | 40 | 100.00 % | 40 | IESO | December 2022[3] | AA |
| Tunis | Ontario | Natural Gas | 40 | 100.00 % | 40 | IESO | [4] | AA |

(1) BC Hydro has the option to purchase Mamquam in November 2021 and every five-year anniversary thereafter.

(2) The Williams Lake energy purchase agreement may extend to September 30, 2019 at the option of BC Hydro.

(3) In December 2017, we entered into a long-term enhanced dispatch contract with the Independent Electricity System Operator ("IESO") for Nipigon for the period November 1, 2018 through December 31, 2022. As a result, the PPA will be terminated effective October 31, 2018. The long-term enhanced dispatch contract provides for Nipigon to receive monthly capacity-type payments based on the original PPA, with adjustment for operational savings that will be shared with the IESO. In addition, the project will function as a market participant and earn energy revenues for those periods during which it operates. In 2018, we will accelerate amortization of the remaining $18.3 million of intangible PPA asset through October 31, 2018.

(4) In December 2014, we entered into an agreement with the Ontario Power Authority and its successor, the IESO for the future operations of the Tunis facility. Subject to meeting certain technical requirements, Tunis will operate under a 15-year agreement with the IESO commencing during the third quarter of 2018. The agreement provides the Tunis project with a fixed monthly payment which escalates annually according to a pre-defined formula while allowing it to earn additional energy revenues for those periods during which it operates. For a further description of the status of these agreements and related renegotiations, see Item 1A. Risk Factors - *The expiration or termination of our PPAs could have a material adverse impact on our business, results of operation and financial condition.*

On December 31, 2017, the enhanced dispatch contracts with the IESO expired at our wholly-owned 40 MW natural gas projects, Kapuskasing and North Bay, located in the Province of Ontario. These projects are currently not in operation.

## General

Historically, the North American electricity industry was characterized by vertically integrated monopolies. During the late 1980s, several jurisdictions began a process of restructuring by moving away from vertically integrated monopolies toward more competitive market models. Rapid growth in electricity demand, environmental concerns, increasing electricity rates, technological advances and other concerns prompted government policies to encourage the supply of electricity from independent power producers. More recently, the North American electricity industry has become more diversified but faces the challenges of declining reserve margins and energy prices and uncertainty resulting from environmental regulations.

According to the North American Electric Reliability Corporation's ("NERC") 2017 Long-Term Reliability Assessment ("LTRA"), published in December 2017, the 10-year forecast compound annual growth rate of the peak summer and winter electricity demand has continued to trend downward. The LTRA reference case shows a compound annual growth rate of 0.6% and 0.6% for the summer and winter seasons, respectively. This is a decline from 0.7% and 0.7%, respectively, in the 2016 LTRA and is the lowest compound annual growth rate on record since NERC began publishing the LTRA. The declining growth rates are expected to continue with the increase in energy efficiency and conservation programs as well as the continued growth of distributed solar and other storage sources.

Despite low projected demand growth, reserve margins are trending down. According to the LTRA, the North American electric power system is undergoing a significant transformation with ongoing retirements of fossil-fired and nuclear capacity as well as growth in natural gas, wind, and solar resources. This shift is caused by several drivers, such as existing and proposed federal, state, and provincial environmental regulations as well as low natural gas prices, in addition to the ongoing integration of both distributed and utility-scale renewable resources. Natural gas-fired generation surpassed coal as the predominant fuel source for electric generation and is the leading fuel type for capacity additions.

## Non-utility power generation

In the independent power generation sector, electricity is generated from a number of energy sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. All of our plants are non-utility electric generating facilities in the North American electrical power generation industry. The electric power industry is one of the largest industries in the United States, generating annualized retail electricity sales of approximately $87 billion through November 2017, based on information published by the Energy Information Administration. A growing portion of the power produced in the United States and Canada is generated by non-utility generators. According to the Energy Information Administration, independent power producers represented approximately 39% of total net generation in 2017. Independent power producers sell the electricity that they generate to electric utilities and other load-serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load-serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers.

## Competition

The power generation industry is characterized by intense competition, and we compete with utilities, industrial companies, yield companies and other independent power producers. Historically low crude and natural gas prices as well as decreased demand have contributed to reduced capacity and energy prices and increasing competition among generators to obtain power sales agreements. We also compete for acquisition and joint-venture opportunities with numerous private equity, infrastructure and pension funds, Canadian and U.S. independent power firms, utility non-regulated subsidiaries and other strategic and financial players.

# REGULATORY MATTERS

## Overview

Our facilities and operations are subject to laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, access to transmission, and the geographical location, zoning, land use and operation aspects of our facilities and properties, including environmental matters.

In the United States, the power generation and sale aspects of our projects are primarily regulated by the Federal Energy Regulation Commission ("FERC"), although most of our projects benefit from the special provisions accorded to Qualifying Facilities ("QFs") or Exempt Wholesale Generators ("EWGs").

In Canada, electricity generation is subject primarily to provincial regulation. Our projects in British Columbia are therefore subject to different regulatory regimes from our projects in Ontario.

## Generating projects

### *United States*

Twelve of our power generating projects are QFs under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), and FERC regulations. A QF falls into one or both of two primary classes, both of which would facilitate one of PURPA's goals to more efficiently use fossil fuels to generate electricity than typical utility plants. The first class of QFs includes energy producers that generate power using renewable energy sources such as wind, solar, geothermal, hydro, biomass or waste fuels. The second class of QFs includes cogeneration facilities, which must meet specific fossil fuel efficiency requirements by producing both electricity and steam versus electricity only.

The generating projects with QF status are currently party to a PPA with a utility or have been granted authority to charge market-based rates or are exempt from FERC rate-making authority. The FERC has granted eight of the projects the authority to charge market-based rates based primarily on a finding that the projects lack market power. The projects with QF status are also exempt from state regulation respecting the rates of electric utilities and the financial or organizational regulation of electric utilities. However, state regulators may review the prudency of utilities entering into PPAs with QFs and the siting of the generation facilities. The majority of our generation is sold by QFs under PPAs that required approval by state authorities.

PURPA, as initially implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided costs. The Energy Policy Act of 2005 (the "EP Act of 2005"), however, established new limits on PURPA's requirement that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. The projects with EWG status are also exempt from state regulation respecting the rates of electric utilities.

Notwithstanding their status as QFs and EWGs, our projects remain subject to various aspects of FERC regulation, including those relating to power marketer status and to oversight of mergers, acquisitions and investments relating to utilities under the Federal Power Act, as amended by the EP Act of 2005. Nine of our projects are also subject to reliability standards developed and enforced by NERC. NERC is a not-for-profit regulatory authority whose mission is to assure the reliability and security of the bulk power system in North America.

Pursuant to its authority, NERC has issued, and the FERC has approved, a series of mandatory reliability standards. Users, owners and operators of the bulk power system can be penalized significantly for failing to comply with the FERC-approved reliability standards. We have designated our Manager of Operational and Regulatory Compliance to oversee compliance with reliability standards and an outside law firm specializing in this area advises us on FERC and NERC compliance, including annual compliance training for relevant employees.

***British Columbia, Canada***

The vast majority of British Columbia's power is generated or procured by BC Hydro. BC Hydro is one of the largest electric utilities in Canada. BC Hydro is owned by the Province of British Columbia and is regulated by the British Columbia Utilities Commission (the "BCUC"), which is governed by the Utilities Commission Act (British Columbia) and is responsible for the regulation of British Columbia's public energy utilities including publicly owned and investor-owned utilities (i.e., independent power producers).

BC Hydro is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers.

All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the BCUC as being "in the public interest." The BCUC may hold a hearing in this regard. Furthermore, the BCUC may make rules governing conditions to be contained in agreements entered into by public utilities for electricity.

The BCUC has adopted the standards developed by NERC as being applicable to, among others, all generators of electricity in British Columbia, including independent power producers. In addition, the BCUC has adopted a number of other standards, including the Western Electricity Coordinating Council ("WECC") standards. As a practical matter, WECC typically administers standards compliance on the BCUC's behalf.

The *Clean Energy Act* (the "Clean Energy Act"), which became law in 2010, sets out British Columbia's energy objectives. The Clean Energy Act states, among other things, that British Columbia aims to accelerate and expand the development of clean and renewable energy sources in British Columbia to, among other things, promote economic development and job creation and continue to work toward the reduction of greenhouse gas emissions. The legislation also explicitly states that British Columbia will encourage the use of waste heat, biogas and biomass to reduce waste. The Government of British Columbia released in April 2016 the *Clean Energy Production in B.C.: An inter-Agency Guidebook for Project Development*, which is consistent with the Clean Energy Act and favors clean and renewable energy sources such as waterpower, windpower and ocean energy generation. BC Hydro is required to meet these objectives and submit reports to the BCUC updating on its progress.

Other provincial regulators in British Columbia having authority over independent power producers include the British Columbia Safety Authority, the Ministry of Environment and the Integrated Land Management Bureau.

***Ontario, Canada***

In Ontario, the Ontario Energy Board ("OEB") is an administrative tribunal with overall responsibility for the regulation and supervision of the natural gas and electricity industries in Ontario and with the authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects.

No person is permitted to own or operate large or medium-scale electricity generation facilities in Ontario without a license from the OEB.

The OEB's general functions include:

- Determination of the rates charged for regulated services in the electricity sector;
- Licensing of market participants;
- Inspections, particularly with respect to compelling production of records and information;
- Market monitoring and reporting, including on anti-competitive practice;
- Consumer advocacy; and
- Enforcement and compliance.

The OEB has the authority effectively to modify licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in fines. While the OEB provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the OEB, and the OEB is required to implement such policy directives.

A number of other regulators and quasi-governmental entities play a role in electricity regulation in Ontario, including the IESO, Hydro One, the Electrical Safety Authority ("ESA") and OEFC.

In 1998, the Legislative Assembly of Ontario passed the Energy Competition Act of 1998, which authorized the establishment of a market in electricity, and reorganized Ontario Hydro into five companies: Ontario Power Generation ("OPG"), the Ontario Hydro Services Company (later renamed Hydro One), the Independent Electricity Market Operator (later renamed the IESO), the ESA, and OEFC. The two commercial companies, Ontario Power Generation and Hydro One, were intended to eventually operate as private businesses rather than as crown corporations. In the fall of 2015, the Province sold off 15% of Hydro One in an IPO with an additional 38% sold through December 31, 2017.

The IESO is responsible for administering the wholesale electricity market and controlling Ontario's transmission grid. The IESO is a non-profit corporation whose directors are appointed by the government of Ontario. The IESO's "Market Rules" form the regulatory framework for the operation of Ontario's transmission grid and electricity market. The Market Rules require, among other things, that generators meet certain equipment and performance standards and certain system reliability obligations. The IESO may enforce the Market Rules by imposing financial penalties. The IESO may also terminate, suspend or restrict participatory rights.

In November 2006, the IESO entered into a memorandum of understanding with NERC, in which it recognized NERC as the "electricity reliability organization" in Ontario. In addition, the IESO has also entered into a similar MOU with both the Northeast Power Coordinating Council (the "NPCC") and NERC. The IESO is accountable to NERC and NPCC for compliance with NERC and NPCC reliability standards. Although the IESO may impose Ontario-specific reliability standards, such standards must be consistent with, and at least as stringent as, NERC's and NPCC's standards.

Effective July 1, 2016, the IESO is changing the definition of what generating facilities are considered part of the Bulk Electric System ("BES"). Any new facility grouped into the BES, which includes all Ontario sites except Kapuskasing, will have to comply with all NERC reliability standards in effect in Ontario. As of January 1, 2015, the IESO is responsible for procuring new electricity generation. As a result, the IESO enters into electricity generation contracts with electricity generators in Ontario from time to time.

The *Green Energy Act* became law in Ontario in 2009 for renewable electricity generation technologies, including via a feed-in tariff program. This Act states that the Government of Ontario is, among other things, committed to fostering the growth of renewable energy projects, to removing barriers to and promoting opportunities for renewable energy projects and to promoting a green economy. From 2009 to 2013, power purchase contracts in respect of large-scale energy projects were awarded under a feed-in-tariff program. Thereafter, large renewable procurement was done by way of a new program, which was suspended in 2016. In December 2017, the Government of Ontario announced a new Long-Term Energy Plan, which includes developing a "made in Ontario" solution that focuses on lowering carbon emissions, among other things.

**Carbon emissions**

*United States – regional and state*

In the United States, during the past several years government action addressing carbon emissions has been focused on the regional and state level. Beginning in 2009, the Regional Greenhouse Gas Initiative ("RGGI") was established by certain Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for $CO_2$ emissions. $CO_2$ allowances are now a tradable commodity in the RGGI states. The nine states currently participating in RGGI have varied implementation plans and schedules. RGGI implemented a new, reduced $CO_2$ cap in 2014, with further reductions of 2.5% each year from 2015 to 2020. The one RGGI state where we have project interests, New York, also provides cost mitigation for independent power projects with certain types of power contracts. California's cap-and-trade program governing greenhouse gas emissions became effective for the electricity sector on January 1, 2013. California, along with British Columbia, Ontario and Quebec, is part of the Western Climate Initiative, which supports the implementation of state and provincial greenhouse gas emissions trading programs. Other states and regions in the United States have considered similar regulations, and it is possible that federal climate legislation will be established in the future.

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases. The two laws are more commonly known as AB 32 (the Global Warming Solutions Act) and SB 1368. In 2016, California enacted SB 32, which expanded the requirements of AB 32. Under AB 32 and SB 32, the California Air Resources Board (the "CARB") is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector) to achieve goals of reaching (i) 1990 greenhouse gas emissions levels by the year 2020, (ii) 40% below 1990 levels by 2030, and (iii) 80% below 1990 emissions levels by 2050. Under the CARB regulations that took effect on January 1, 2013, electricity generators and certain other facilities are now subject to an allowance for greenhouse gas emissions, with allowances allocated by both formulas set by the CARB and auctions.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission (the "CPUC") and the CARB, establish greenhouse gas emission performance standards and implement regulations for PPAs for a term of five or more years entered into prospectively by publicly owned electric utilities. The legislation directs the California Energy Commission to establish the performance standard as one not exceeding the rate of greenhouse gas emitted per megawatt hour ("MWh") associated with combined-cycle, gas turbine baseload generation, such as our North Island project.

*United States – federal*

The U.S. Environmental Protection Agency (the "EPA") has taken several recent actions respecting $CO_2$ emissions. The EPA's actions include its December 2009 finding of "endangerment" to public health and welfare from greenhouse gases, its issuance in September 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule which required large sources, including power plants, to monitor and report greenhouse gas emissions to the EPA annually beginning in 2011, and its issuance in May 2010 of its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, which under a phased-in approach requires large industrial facilities, including power plants, to obtain permits to emit, and to use best available control technology to curb emissions of, greenhouse gases. In addition, in August 2015, the EPA issued its final rule regulating carbon emissions from existing electric generating units, which is referred to as the Clean Power Plan (the "CPP"). As a result of judicial challenge, however, the CPP has not been implemented, and more recently the Trump administration has pursued efforts to revoke it. On February 9, 2016, the U.S. Supreme Court granted a stay of the implementation of the CPP as it would have applied to existing power plants, including the requirement that states submit their initial plans by September 2016, and proceedings before the U.S. Court of Appeals for the District of Columbia Circuit are in abeyance pending further agency action. At the administrative level, on March 28, 2017, President Trump signed an Executive Order directing the EPA to review and, consistent with applicable law, initiate a rulemaking to suspend, revise or rescind the Clean Power Plan and EPA's standards for new power plants. Recently, on October 10, 2017, the EPA issued a proposed rule to repeal the CPP for existing power plants, and pursuant to an April 2017 announcement it is continuing to review whether to suspend, revise or rescind the greenhouse gas standards for new power plants. The public comment period on the proposed rule for existing plants ran to January 16, 2018. The EPA also announced its intent to issue an advance notice of proposed rulemaking to solicit information on alternate systems of greenhouse gas emissions reduction from power plants. Any such rulemaking activities could take years to complete, and are likely to draw legal challenges. At this time, we cannot predict the outcome of the current legal challenges to the CPP or any legal challenges to future administrative actions.

*Canada - federal*

In Canada, the federal government and the provincial governments of British Columbia and Ontario have implemented greenhouse gas reporting regulations and are developing additional programs to address greenhouse gas emissions. Under the 2004 federal Greenhouse Gas Emissions Reporting Program ("GHGRP"), all facilities which emit 50,000 tonnes or more of $CO_2$eq per year are required to submit reports on their emissions to Environment Canada.

On October 3, 2016, the Government of Canada announced its proposed pan-Canadian approach for the pricing of carbon pollution. Under the federal approach, the provinces and territories can put a direct price on carbon pollution or they can adopt a cap-and-trade system. On January 15, 2018, the Government of Canada released the draft Greenhouse Gas Pollution Pricing Act, setting out the mechanics proposed to be used to backstop the federal government's pan-Canadian approach to carbon pricing in provinces that have not implemented, by January 1, 2019, a carbon pricing system that the federal government has determined complies with its carbon price requirements. The federal backstop regime requires a minimum Cdn$20/tonne of carbon dioxide equivalent ("tCO2e") carbon price by January 1, 2019, increasing by Cdn$10 increments each following year to 2022. Alberta, British Columbia, Ontario and Québec already have compliant carbon pricing systems in place and are not expected to be subject to the federal backstop regime.

*Canada – British Columbia*

The Government of British Columbia has enacted a number of significant pieces of climate action legislation that frame British Columbia's approach to reducing greenhouse gas emissions with the goal of supporting its participation in the emerging low-carbon economy.

One key piece of legislation is the Greenhouse Gas Reduction Targets Act ("GGRTA"), which came into force in 2008 and sets legislated targets for the reduction of greenhouse gas emissions in British Columbia. Using 2007 as a base year, GGRTA (along with related Ministerial Orders) requires that emissions must be reduced by a minimum of 18% by 2016, 33% by 2020 and 80% by 2050. Also required in connection with GGRTA are (from 2010 onward) British Columbia Greenhouse Gas Inventory Reports (reports are prepared in even-numbered years and tables are updated in odd-numbered years), Community Energy and Emissions Inventory Reports (prepared every two years) and Carbon Neutral Action Reports (prepared annually), all of which are designed to provide scientific, comparable and consistent reporting of greenhouse gas sources.

Other related, key pieces of legislation include the *Carbon Tax Act* ("CTA") and the *Greenhouse Gas Industrial Reporting and Control Act* ("GGIRCA"). CTA operates to put a price on greenhouse gas emissions, providing an incentive for sustainable choices and practices by producers of greenhouse gases. GGIRCA came into force on January 1, 2016 and combined several pieces of British Columbia's existing greenhouse gas legislation into a single legislative framework. It includes the ability to set a greenhouse gas emissions intensity benchmark for regulated industries and enables the benchmark to be met through flexible options, such as purchasing offsets or paying a set price per tonne of greenhouse gas emissions that would be dedicated to a technology fund. Three regulations necessary to implement GGIRCA also came into force on January 1, 2016: the *Greenhouse Gas Emission Reporting Regulation* ("GGERR"), the *Greenhouse Gas Emission Administrative Penalties and Appeals Regulation* ("GGEAPAR") and the *Greenhouse Gas Emission Control Regulation* ("GGECR"). GGERR establishes compliance reporting requirements and ensures that industrial operations that emit more than 10,000 carbon dioxide equivalent tonnes per year report their greenhouse gas pollution each year. GGEAPAR establishes the process for when, how much, and under what conditions administrative penalties may be levied for non-compliance with GGIRCA or the regulations made under GGIRCA. GGECR establishes the BC Carbon Registry and sets criteria for developing emission offsets issued by the provincial government. GGECR also establishes the price for funded units issued under GGIRCA that would go towards a technology fund. Regulated operations will purchase offsets from the market or funded units from government to meet emission limits. Funded unit revenue that goes to a technology fund will also support the development of clean technologies with significant potential to reduce British Columbia's emissions over the long term.

*Canada - Ontario*

Ontario has a new *Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulation O*. Reg. 143/16 under the *Climate Change Mitigation and Low-carbon Economy Act, 2016* (the "Ontario Cap and Trade Act") which has applied since January 1, 2017. Ontario's reporting rules require a report for all facilities which release 10,000 Tonnes CO2eq or more per year to be made using Environment Canada's Single Window System. For 2016 (the last year for which emission reports had been published at the beginning of 2018), each of our three natural gas powered generating facilities in Ontario reported emissions in excess of 115,000 Tonnes of CO2eq (more than 317,000 Tonnes of CO2eq in total) on the federal registry. All three of these plants ceased to operate at the end of 2017.

In December 2015, Ontario, Manitoba and Quebec signed a Memorandum of Understanding signaling their intentions to share information and link their cap-and-trade programs, which effort is expected to strengthen and expand the coverage of the Western Climate Initiative. On September 22, 2017 Ontario formally joined the Québec-California carbon market, effective January 1, 2018. This will allow all three governments to hold joint auctions of greenhouse gas emission allowances and to harmonize regulations and reporting.

In Ontario, facilities with annual greenhouse gas emissions of 25,000 tonnes or more are generally required by law to participate in the Ontario cap-and-trade regime. However, under *The Cap and Trade Program Regulation O*. Reg. 144/16 (the "Cap and Trade Program"), facilities which primarily generate electricity using natural gas from a local distributor are excluded from the mandatory registration requirements under the Ontario Cap and Trade Act and participate in the Ontario Cap and Trade Program through the payment of the carbon price charged by the local natural gas distributor on natural gas delivered after the end of 2016. Although the details of arrangements for the recovery of these additional costs depend on the terms of the applicable PPA, the IESO has stated generally that "the electricity sector will see the cost of carbon reflected in the wholesale electricity price when natural gas-fired resources are on the margin" and it is generally expected that most, if not all, of the incremental carbon price paid by generators to local natural gas distributors will be recoverable by the generators under the applicable PPAs, which will have the effect of making electricity generated from natural gas increasingly incrementally expensive over time.

*Renewable Energy*

Additionally, more than half of the U.S. states and most Canadian provinces have set mandates requiring the achievement of certain levels of renewable energy production and/or energy efficiency during target timeframes. This includes generation from wind, solar and biomass, and/or renewable fuel mandates. For example, in 2011, California enacted a law requiring retail sellers of electricity to deliver 33% of their customers' electricity requirements from renewable resources, as defined in the statute, by 2020. In 2015, California enacted SB 350, which increases the amount of electricity from renewable resources that California retail sellers must deliver after 2020 to 40% of retail sales by

December 2024, 45% of retail sales by December 2027, and 50% of retail sales by December 2030. In order to meet $CO_2$ reduction goals, changes in the generation fuel mix are forecasted to include a reduction in existing coal resources, higher reliance on natural gas and renewable energy resources and an increase in demand-side resources. Investments in new or upgraded transmission lines will be required to move increasing renewable generation from more remote locations to load centers.

In December 2015, 195 countries participating in the United Nations Framework Convention on Climate Change ("UNFCC"), at its 21st Conference of the Parties meeting ("COP21") held in Paris, adopted a new global agreement on the reduction of climate change (the "Paris Agreement"). The Paris Agreement became effective in November 2016, after it had been ratified by a sufficient number of countries. The Paris Agreement sets a goal of holding the increase in global average temperature to well below 2 degrees Celsius and pursuing efforts to limit the increase to 1.5 degrees Celsius, to be achieved by aiming to reach a global peaking of greenhouse gas emissions as soon as possible. The Paris Agreement consists of two elements: a legally binding commitment by each participating country to set an emissions reduction target, referred to as "nationally determined contributions" or "NDCs", with a review of the NDCs that could lead to updates and enhancements every five years beginning in 2023 (Article 4) and a transparency commitment requiring a participating countries to disclose in full their progress (Article 13). Accordingly, the Paris Agreement may result in additional regulations to reduce carbon emissions in coming years.

Canada ratified the Paris Agreement, and submitted the NDC that included a 2030 target of 30% below 2005 levels. The United States also submitted an NDC, which called for reducing its net greenhouse gas emissions by 26-28% below 2005 levels by 2025. However, the Trump Administration has issued a statement indicating it intends to withdraw from the Paris Agreement. In light of the legislative, judicial and executive factors influencing regulatory action, significant uncertainty exists as to how greenhouse gas restrictions in the U.S. will impact our facilities in the future.

## EMPLOYEES

As of February 27, 2018, we had 246 employees, 181 in the United States and 65 in Canada. Of our Canadian employees, 24 are covered by a collective bargaining agreement which will expire on December 31, 2018 and 21 are covered by a collective bargaining agreement which will expire on December 31, 2020. During 2017, we did not experience any labor stoppages or labor disputes at any of our facilities.

## AVAILABLE INFORMATION

We make available, free of charge, on our website, www.atlanticpower.com, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Additionally, we make available on our website and the System for Electronic Document Analysis and Retrieval at www.sedar.com, our Canadian securities filings. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at www.sec.gov. We are not a foreign private issuer, as defined in Rule 3b-4 under the Exchange Act.

Information contained on our website or that can be accessed through our website is not incorporated into and does not constitute a part of this Annual Report on Form 10-K. We have included our website address only as an inactive textual reference and do not intend it to be an active link to our website.

## ITEM 1A. RISK FACTORS

*This section highlights specific risks that could affect our Company. You should carefully consider each of the following risks and all of the other information set forth in this Annual Report on Form 10-K. Based on the information currently known to us, we believe the following information identifies the most significant risk factors affecting our Company. However, the risks and uncertainties described below are not the only ones related to our business and are* *not necessarily listed in the order of their importance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business, results of operations or financial condition.*

*If any of the following risks and uncertainties develops into actual events or if the circumstances described in the risks and uncertainties occur or continue to occur, these events or circumstances could have a material adverse effect on our business, results of operations or financial condition. These events could also have a negative effect on the trading price of our securities.*

**Risks Related to Our Structure**

***We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities***

We continue to focus on executing our business plan, including the objectives of enhancing the value of our existing assets through discretionary capital investments and commercial activities, delevering our balance sheet to improve our cost of capital and ability to compete for new investments, improving our cost structure and reducing overhead. However, we may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities.

Our ability to make required payments under our outstanding indebtedness, as well as meeting the greater of the requirements of the 50% cash sweep or the targeted debt balance, or to prepay or redeem any such indebtedness, will depend on our financial and operating performance, including our ability to generate cash flow from operations in the future. As a result, we may be required to refinance such indebtedness and/or obtain third-party financing in order to repay, redeem or refinance such indebtedness when it comes due. There can be no assurance that our business will generate sufficient cash flow from operations or that future borrowings or refinancing opportunities will be available to us at an acceptable cost, in amounts sufficient, or at all, to enable us to service our debt obligations or to repay or redeem any such indebtedness at maturity, particularly because of our high levels of debt and the debt incurrence restrictions imposed by the various agreements governing our indebtedness. Steps taken to refinance our indebtedness or obtain other third-party financing, if any, may not be successful and may not permit us to meet our scheduled debt service obligations, which could have a material adverse effect on our liquidity and financial condition.

In addition, a payout of a significant portion of our cash flow to service our debt, including pursuant to the mandatory amortization feature of the Credit Facilities, or through preferred dividends, may result in us not retaining a sufficient amount of cash to finance growth and reinvestment opportunities, including through the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us. As a result, we may have to forego growth and reinvestment opportunities that would otherwise be desirable, if we do not find alternative sources of financing for such opportunities. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could also limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors. We cannot provide any assurance that we will be able to identify, finance or close any transactions associated with any such growth or reinvestment opportunities on acceptable terms or timing, or at all.

Further, if we are unable to generate sufficient cash flow from operations, our ability to support our liquidity needs, including, but not limited to servicing our debt obligations, including pursuant to the mandatory amortization feature of the Credit Facilities, or financing internal or external growth opportunities, will depend on our ability to access the credit and capital markets, neither of which may be available to us on acceptable terms, or at all. Further, access to the credit and capital markets and the cost and availability of credit may be adversely affected by factors beyond our control, including turmoil in the financial services industry, volatility in securities trading markets and general economic conditions. We cannot provide any assurance that we will be able to access the credit or capital markets on acceptable terms or timing, or at all.

***Our Credit Facilities contain certain terms, covenants and restrictions that could impact our available cash flow and restrict our ability to make acquisitions or investments or issue additional indebtedness***

Our Credit Facilities contain certain terms, covenants and restrictions, including a mandatory amortization feature and customary prepayment provisions. Such terms, covenants and restrictions may impact our available cash flow and limit our ability to retain sufficient amounts of cash to service our debt obligations or finance internal or external growth opportunities. Our Credit Facilities are a primary source of our liquidity. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources”.

The covenants under the Credit Facilities include a requirement that APLP Holdings Limited Partnership (“APLP Holdings”) and its subsidiaries maintain certain leverage and interest coverage ratios (each, as defined in the credit agreement governing the Credit Facilities (the “Credit Agreement”)). The Credit Facilities also contain customary restrictions and limitations on the Partnership’s and its subsidiaries’ ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case, subject to customary carve-outs and exceptions and various thresholds. Any such limitations could restrict our ability to, among other things, make acquisitions or investments or issue additional indebtedness.

***Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make preferred dividend payments, acquisitions or investments or issue additional indebtedness we otherwise would seek to do***

The degree to which we are leveraged on a consolidated basis could have important consequences for our shareholders and other stakeholders, including:

- our ability in the future to obtain additional financing for, among other things, the repayment or redemption of indebtedness and other debt service obligations and investment in internal and external growth opportunities, including the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us, or other purposes;
- our ability to refinance indebtedness on terms acceptable to us or at all;
- our ability to satisfy debt service and other obligations;
- our vulnerability to general adverse industry conditions and economic conditions, including but not limited to adverse changes in foreign exchange rates and commodity prices;
- the availability of cash flow to fund other corporate purposes and grow our business;
- our flexibility in planning for, or reacting to, changes in our business and the industry; and
- our competitive position relative to our competitors that are not as highly leveraged.

As of December 31, 2017, our consolidated long-term debt represented approximately 81% of our total capitalization, comprised of debt and balance sheet equity.

The agreements governing our indebtedness limit, but do not prohibit, the incurrence of additional indebtedness. Our current or future borrowings could increase the level of financial risk to us and, to the extent that the interest rates are not fixed and rise, or that borrowings are refinanced at higher rates, our available cash flow and results of operations could be adversely affected. Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 82% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

As of December 31, 2017, we had (i) no amount outstanding and $80.5 million issued in letters of credit under our revolving credit facility, (ii) $107.1 million of outstanding convertible debentures, and (iii) $738.7 million of outstanding Term Loan, Medium term Notes and non-recourse project-level debt.

In addition, some of our projects currently have non-recourse term loans or other financing arrangements in place with various lenders. These financing arrangements are typically secured by all of the project assets and contracts as well as our equity interests in the project. The terms of these financing arrangements generally impose many covenants and obligations on the part of the borrower. For example, some of these agreements contain requirements to maintain specified historical, and in some cases, prospective debt service coverage ratios before cash may be distributed from the relevant project to us, which would adversely affect our available cash flow. We have, in the past, failed to meet the cash flow coverage ratio tests at certain of our projects, which restricted those projects from making cash distributions. Although all of our projects with non-recourse loans are currently meeting their debt service requirements, we cannot provide any assurances that our projects will generate enough future cash flow to meet any applicable ratio tests in order to be able to make distributions to us.

In many cases, an uncured default by any party under key project agreements (such as a PPA or a fuel supply agreement) will also constitute a default under the project's term loan or other financing arrangement. Failure to comply with the terms of these term loans or other financing arrangements, or events of default thereunder, may prevent cash distributions by the particular project(s) to us and may entitle the lenders to demand repayment and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, failure to comply with the terms, restrictions or obligations of any of our revolving credit facility, convertible debentures or Credit Facilities, or the preferred shares of the Partnership, or any other financing arrangements, borrowings or indebtedness, or events of default thereunder, may entitle the lenders to demand repayment, accelerate related debt as well as any other debt to which a cross-default or cross-acceleration provision applies and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, if and for as long as we have failed to declare, or are in arrears on the payment of, dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares, the Partnership will not make any distributions on its limited partnership units. Additionally, if our lenders under our indebtedness demand payment, we may not, at that time, have sufficient cash and cash flows from operating activities to repay such indebtedness.

Our failure to refinance or repay any indebtedness when due could constitute a default under such indebtedness and restrict our ability to take certain actions, including paying dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares. In addition, any covenant breach or event of default could harm our credit rating and our ability to obtain additional financing on acceptable terms or at all. The occurrence of any of these events could have a material adverse effect on our business, results of operations, financial condition and liquidity.

Paying dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares could also be restricted if we fail to meet the targeted debt balances of the Credit Facilities, even though failing to do so would not result in an event of default.

***Exchange rate volatility may affect our available cash flow and results of operations***

Our dividend payments on our preferred shares and our interest payments on some of our corporate-level long-term debt and convertible debentures are denominated in Canadian dollars. Conversely, some of our projects' revenues and expenses are denominated in U.S. dollars. Our Canadian dollar-denominated debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar-denominated debt. Although we currently generate sufficient revenues in Canadian dollars to fund our Canadian dollar obligations, future exchange rate volatility or changes to our Canadian dollar revenues could expose us to currency exchange rate risks, against which we do not typically hedge. Any arrangements to mitigate this exchange rate risk may not be sufficient to fully protect against this risk. If hedging transactions do not fully protect against this risk, changes in the currency exchange rate between U.S. and Canadian dollars could adversely affect our available cash flow and results of operations.

***A downgrade in our credit rating or in the credit rating of our outstanding debt securities, or any deterioration in credit quality, could negatively affect our ability to access capital and our ability to hedge, and could trigger termination rights under certain contracts***

A downgrade in our credit rating, a downgrade in the credit rating of our outstanding debt securities, or any deterioration in credit quality could adversely affect our ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities, restrict access to our revolving credit facility and/or trigger termination rights or enhanced disclosure requirements under certain contracts to which we are a party. Any downgrade of our corporate credit rating could also cause counterparties to require us to post letters of credit or other additional collateral, make cash prepayments, or obtain a guarantee agreement, all of which would expose us to additional costs and/or could adversely affect our ability to comply with covenants or other obligations under any of our revolving credit facility, convertible debentures or unsecured notes or any other financing arrangements, borrowings or indebtedness (or could constitute an event of default under any such financing arrangements, borrowings or indebtedness that we may be unable to cure), any of which could have a material adverse effect on our business, results of operations and financial condition.

***Changes in our creditworthiness may affect the value of our common shares***

Changes to our perceived creditworthiness and ability to meet our required covenants on an ongoing basis may affect the market price or value and the liquidity of our common shares.

***The future issuance of additional common shares could dilute existing shareholders***

From time to time, we may decide to issue additional common shares, redeem outstanding debt for common shares, repay outstanding principal amounts under existing debt by issuing common shares, or issue equity-related securities such as convertible debt. We may also, from time to time, decide to issue common shares to meet strategic objectives or in connection with acquiring assets or pursuing broader strategic options. We also have the option to convert our convertible debentures to common shares at their respective maturity dates. The issuance of additional common shares may have a dilutive effect on shareholders and may adversely impact the price of our common shares.

***Volatile capital and credit markets may adversely affect our ability to raise capital on favorable terms and may adversely affect our business, results of operations, financial condition and cash flows***

Disruptions in the capital and credit markets in the United States, Canada or abroad can adversely affect our ability to access the capital markets. Our access to funds under our credit facility is dependent on the ability of the banks that are parties to the facility to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Longer-term disruptions in the capital and credit markets as a result of turmoil in the financial services industry, volatility in securities trading markets and general economic conditions could result in an inability to support our liquidity needs, including, but not limited to, the service of our debt obligations or financing of internal or external growth opportunities. See "—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities."

Our ability to arrange for financing on a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

- general industry, economic and capital market conditions;
- the availability of bank credit;
- investor confidence;

- our financial condition, performance and prospects as well as companies in our industry or similar financial circumstances; and
- changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available to us, either as a result of market conditions or our financial condition, we may not be able to service our debt obligations or finance internal or external growth opportunities, any of which would adversely affect our business, results of operations and financial condition.

***We have guaranteed the performance of some of our subsidiaries, which may result in substantial costs in the event of non-performance***

We have issued certain guarantees of the performance of some of our subsidiaries in certain situations, which obligates us to perform in the event that the subsidiaries do not perform. In the event of non-performance by the subsidiaries, we could incur substantial cost to fulfill our obligations under these guarantees. Such performance guarantees could have a material impact on our business, results of operations, financial condition and cash flows. See Notes 11 and 23 to the consolidated financial statements for information on our guarantee obligations.

***We have anti-takeover protections that may discourage, delay or prevent a change in control that could benefit our shareholders.***

The *Business Corporations Act* (British Columbia) (the "BCBCA") and our Articles of Continuance contain provisions that could make it more difficult for a third party to acquire us without the consent of our Board of Directors ("Board"). These provisions include:

- As a notice of meeting is required to include certain particulars in the case where a shareholder meeting is being requisitioned by shareholders, our Board must be given advance notice regarding special business that is to be brought by such requisitioning shareholders before the shareholder meeting. For special business, advance notice describing the special business to be discussed at the meeting must be provided and that notice must include any documents to be approved or ratified as an addendum or state that such document will be available for inspection at our records office or other reasonably accessible location;
- Under the BCBCA, shareholders may make proposals for matters to be considered at the annual general meeting of shareholders, provided that such shareholders represent at least 1% of the voting shares of a company or such shares have a fair market value of at least Cdn$2,000. Such proposals must be sent to us in advance of any proposed meeting by delivering a timely written notice in proper form to our registered office. The notice must include information on the business the shareholder intends to bring before the meeting. These provisions could have the effect of delaying until the next shareholder meeting shareholder actions that are favored by the holders of a majority of our outstanding voting securities; and
- Casual vacancies on our Board can be approved prior to the next annual meeting of shareholders by the directors of our Board of Directors.

If we experience a change of control, unless we elect to make a voluntary prepayment of the term loan under the Credit Facilities, the Partnership will be required to offer each electing lender to prepay such lender's term loans under the Credit Facilities at a price equal to 101% of par. Additionally, a change in control will permit holders of our convertible debentures to require that we purchase the debentures upon the conditions set forth in the respective indenture governing the debentures, which may discourage, delay or prevent a change of control or the acquisition of a substantial block of our common shares. In addition, some of our PPAs or other commercial agreements may contain change of control provisions.

We have a shareholder rights plan in place that may delay or prevent a change of control or the acquisition of a substantial block of our common shares and may make any future unsolicited acquisition attempt more difficult. Under the rights plan:

- The rights will generally become exercisable if a person or group acquires 20% or more of Atlantic Power's outstanding common shares (unless such transaction is a "permitted bid" or a transaction to which the application of the shareholders rights plan has been waived pursuant to the terms of the plan) and thus becomes an "acquiring person." A "permitted bid" is an offer pursuant to which, among other things, such person or group agrees to hold the offer open to all shareholders for a period longer than the statutorily required period;

- Each right, when exercisable, will entitle the holder, other than the "acquiring person," to acquire shares of Atlantic Power's common shares at a significant discount to the then-prevailing market price; and

- As a result, the rights plan may cause substantial dilution to a person or group that becomes an "acquiring person" and may discourage or delay a merger or acquisition that shareholders may consider favorable, including transactions in which shareholders might otherwise receive a premium for their shares.

***Our common shares may not continue to be qualified investments under Canadian tax laws***

There can be no assurance that our common shares will continue to be qualified investments under relevant Canadian tax laws for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, registered disability savings plans and tax-free savings accounts. Canadian tax laws impose penalties for the acquisition or holding of non-qualified or ineligible investments.

***We are subject to Canadian tax***

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes, and dividends paid by us are generally subject to Canadian withholding tax if paid to a shareholder that is not a resident of Canada. We hold promissory notes from our U.S. holding companies (the "Intercompany Notes") and are required to include, in computing our taxable income, interest on the Intercompany Notes.

***Canadian federal income tax laws and policies could be changed in a manner which adversely affects holders of our common shares***

There can be no assurance that Canadian federal income tax laws and Canada Revenue Agency administrative policies respecting the Canadian federal income tax consequences generally applicable to us, to our subsidiaries, or to a U.S. or Canadian holder of common shares will not be changed in a manner which adversely affects holders of our common shares.

***Our current structure may be subject to additional U.S. federal income tax liability***

Under our current structure, our subsidiaries that are incorporated in the United States are subject to U.S. federal income tax on their income at regular corporate rates (currently as high as 21%, plus state and local taxes), and two of our U.S. holding companies will claim interest deductions with respect to the Intercompany Notes in computing their income for U.S. federal income tax purposes. To the extent any interest expense under the Intercompany Notes is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding companies will increase, which could materially affect the after-tax cash available to distribute to us.

We received advice from our U.S. tax counsel at the time of the issuance, based on certain representations by us and our U.S. holding companies and determinations made by our independent advisors, as applicable, that the Intercompany Notes should be treated as debt for U.S. federal income tax purposes. However, it is possible that the Internal Revenue Service (the "IRS") could successfully challenge these positions and assert that any of these arrangements should be treated as equity rather than debt for U.S. federal income tax purposes or that the interest on such arrangements is otherwise not deductible. In this case, the otherwise deductible interest would be treated as non-deductible distributions and, in the case of the Intercompany Notes, may be subject to U.S. withholding tax to the extent our respective U.S. holding company had current or accumulated earnings and profits. The determination of debt or equity treatment for U.S. federal income tax purposes is based on an analysis of the facts and circumstances. There is no clear statutory definition of debt for U.S. federal income tax purposes, and its characterization is governed by principles developed in case law, which analyzes numerous factors that are intended to identify the nature of the purported creditor's interest in the borrower.

Not all courts have applied this analysis in the same manner, and some courts have placed more emphasis on certain factors than other courts have. To the extent it were ultimately determined that our interest expense on the Intercompany Notes were disallowed, our U.S. federal income tax liability for the applicable open tax years would materially increase, which could materially affect the after-tax cash available to us to distribute. Alternatively, the IRS could argue that the interest on the Intercompany Notes exceeded or exceeds an arm's length rate, in which case only the portion of the interest expense that does not exceed an arm's length rate may be deductible and the remainder may be subject to U.S. withholding tax to the extent our U.S. holding companies had current or accumulated earnings and profits. We have received advice from independent advisors that the interest rate on these debt instruments was and is, as applicable, commercially reasonable under the circumstances, but the advice is not binding on the IRS.

Furthermore, our U.S. holding companies' deductions attributable to the interest expense on the Intercompany Notes may be limited by the amount by which each U.S. holding company's net interest expense (the interest paid by each U.S. holding company on all debt, including the Intercompany Notes, less its interest income) exceeds 30% of its adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, and, for tax years beginning before January 1, 2022, depreciation and amortization). Any disallowed interest expense may currently be carried forward to future years. In addition, if our U.S. holding companies do not make regular interest payments as required under these debt agreements, other limitations on the deductibility of interest under U.S. federal income tax laws could apply to defer and/or eliminate all or a portion of the interest deduction that our U.S. holding companies would otherwise be entitled to.

In addition, recently enacted U.S. tax legislation made significant changes to the U.S. federal income tax rules applicable to our activities in the United States. Although the tax legislation enacted on December 22, 2017 reduced the federal corporate income tax rate from 35% to 21%, it also added additional limitations on deductions attributable to interest expense (discussed in the preceding paragraph) and introduced "base erosion" rules that may effectively limit the tax deductibility of certain payments made by U.S. entities to non-U.S. affiliates. We are continuing to evaluate the full effect of this legislation on our business and operations, although our preliminary estimate based on guidance available as of the date of this filing is that the interest expense limitation and base erosion and anti-abuse tax will not have a material impact to cash taxes in future tax years.

Our U.S. holding companies have existing net operating loss carryforwards that we can utilize to offset future taxable income. Some of these loss carryforwards are subject to an annual limitation on their use. Although we expect these losses will be available to us as a future benefit, in the event that they are successfully challenged by the IRS or subject to additional future limitations, including, but not limited to, as a result of implementation of any of the potential options we are considering, our ability to realize these benefits may be limited. Although not expected, a reduction in our net operating losses, or additional limitations on our ability to use such losses, may result in a material increase in our future income tax liability.

***Atlantic Power Preferred Equity Ltd. is subject to Canadian tax, as is Atlantic Power's income from the Partnership***

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes. See "Risks Related to Our Structure—We are subject to Canadian tax." We are required to include in computing our taxable income any income earned by the Partnership. In addition, Atlantic Power Preferred Equity Ltd., a subsidiary of the Partnership, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes. Atlantic Power Preferred Equity Ltd. is liable to pay its applicable Canadian taxes.

### Risks Related to Our Business and Our Projects

***The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition***

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between September 30, 2018 and December 31, 2037. See Item 1. Business—Our Organization and Segments for details about our projects' PPAs and related expiration dates. In addition, these PPAs may be subject to termination prior to expiration in certain circumstances, including default by the project. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. It is possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. When the affected project temporarily or permanently ceases operations, or when we have an expectation that we will be unable to renew or renegotiate the PPA, the value of the project may be impaired such that we would be required to record an impairment loss under applicable accounting rules. See "—Impairment of goodwill or long lived assets could have a material adverse effect on our business, results of operations and financial condition."

The enhanced dispatch contracts for our Kapuskasing and North Bay projects expired on December 31, 2017. These two projects, which are no longer under any contractual arrangements and are not in operation, contributed approximately 25% of our 2017 Project Adjusted EBITDA. Another ten of our projects, representing 57% of our operating net MW and 25% of our 2017 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire within the next five years. These projects are Naval Station (2018), North Island (2018), Naval Training Center (2018), Kenilworth (2018), Williams Lake (2019), Oxnard (2020), Calstock (2020), Manchief (2022), Frederickson (2022) and Moresby Lake (2022). Additionally, the enhanced dispatch contract at our Nipigon project expires at the end of 2022. Nipigon represents 7% of our 2017 Project Adjusted EBITDA.

***Our projects depend on their electricity and thermal energy customers and there is no assurance that these customers will perform their obligations or make required payments***

Each of our projects relies on one or more PPAs, steam sales agreements or other agreements with one or more utilities or other customers for a substantial portion of its revenue. At times, we rely on a single customer or a limited number of customers to purchase all or a significant portion of a project's output. In 2017, the largest customers of our power generation projects, including projects recorded under the equity method of accounting, are IESO, Niagara Mohawk Power Corporation, SDG&E and BC Hydro, which purchase approximately 20%, 11%, 10% and 10%, respectively, of the net electric generation capacity of our projects. If a customer stops purchasing output from our power generation projects or purchases less power than anticipated, such customer may be difficult to replace, if at all. Further concentration of our customers would increase our dependence on any one customer. Our cash flows and results of operations, including the amount of cash available to make payments on our indebtedness, are highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their contractual obligations or make required payments.

Further, our customers generally have investment-grade credit ratings, as measured by Standard & Poor's. Customers that have assigned ratings at the top end of the range have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the bottom end of the range have the weakest capacity. Agency ratings are subject to change, and there can be no assurance that a ratings agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

***Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition***

Those of our projects operating without a PPA or with PPAs based on spot market pricing for some or all of their output will be exposed to fluctuations in the wholesale price of electricity. In addition, as PPAs expire or terminate, the relevant project will be required to either negotiate a new PPA or sell into the electricity wholesale market, in which case the prices for electricity will depend on market conditions at the time, which may not be favorable. The open market wholesale prices for electricity are very volatile. Long and short-term power prices may fluctuate substantially due to other factors outside of our control, including:

- changes in generation capacity in the electricity markets, including the addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation facilities, expansion or retirement of existing facilities or additional transmission capacity;
- electric supply disruptions, including plant outages and transmission disruptions;
- fuel transportation capacity constraints;
- weather conditions;
- changes in the demand for power or in patterns of power usage;
- development of new fuels and new technologies for the production or storage of power;
- development of new technologies for the production of natural gas;
- availability of competitively priced renewable fuel sources;
- available supplies of natural gas, crude oil and refined products, and coal;
- interest rate and foreign exchange rate fluctuation;
- availability and price of emission credits;
- geopolitical concerns affecting global supply of oil and natural gas;
- general economic conditions which impact energy consumption in areas where we operate; and
- power market, fuel market and environmental regulation and legislation.

The market price for electricity is affected by changes in demand for electricity. Factors such as economic slowdown, worse than expected economic conditions, milder than normal weather, the growth of energy efficiency and efforts aimed at energy conservation, among others, could reduce energy demand or significantly slow the growth in demand for electricity, thereby reducing the market price for electricity. A reduction in demand could contribute to conditions that no longer support the continued operation of certain power generation projects, which could adversely affect our results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs, among others.

Our most significant exposure to market power prices is at our Morris and Chambers projects. At Chambers, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is economical to do so, and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the utility takes less generation, which negatively affects the project's operating margin. At Morris, approximately 68% of the facility's capacity is currently not contracted. The facility can generate and sell this excess capacity into the grid at market prices. If market prices do not justify the increased generation, the project has no requirement to sell any excess capacity. As a result, fluctuations in the price of electricity may have a material adverse effect on the operating margins of these facilities and on our business, results of operations and financial condition.

***Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects***

The amount of energy generated at the projects is highly dependent on suppliers under certain fuel supply agreements fulfilling their contractual obligations. The loss of significant fuel supply agreements or an inability or failure by any supplier to meet its contractual commitments may adversely affect our results.

Upon the expiration or termination of existing fuel supply agreements, we or our project operators will have to renegotiate these agreements or may need to source fuel from other suppliers. We may not be able to renegotiate these agreements or enter into new agreements on similar terms. There can be no assurance as to availability of the supply or pricing of fuel under new arrangements, and it can be very difficult to accurately predict the future prices of fuel. If our suppliers are unable to perform their contractual obligations or we are unable to renegotiate our fuel supply agreements, we may seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price. Changes in market prices for natural gas, biomass, coal and oil may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- availability and price of emission credits;
- additional generating capacity;
- disruption or other constraints or inefficiencies of electricity, gas or coal transmission or transportation;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil, refined products and coal production levels;
- changes in market liquidity;
- governmental regulation and legislation; and
- our creditworthiness and liquidity, and the willingness of fuel suppliers/transporters to do business with us.

Revenues earned by our projects may be affected by the availability, or lack of availability, of a stable supply of fuel at reasonable or predictable prices. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. To the extent possible, our projects attempt to match fuel cost setting mechanisms in supply agreements to energy payment formulas in the PPA and to provide for indexing or pass-through of fuel costs to customers. In cases where there is no pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies. To the extent that costs are not matched well to PPA energy payments, pass-through of fuel costs is not allowed or hedging strategies are unsuccessful, increases in fuel costs may adversely affect our results of operation. This may have a material adverse effect on our business, results of operations and financial condition. Our energy payments at our Orlando project are subject to fluctuations as the energy payments are comprised of a fuel component based on an index of the cost of coal.

***Our projects may not operate as planned***

The ability of our projects to meet availability requirements and generate the required amount of power to be sold to customers under the PPAs are primary determinants of the amount of cash that will be distributed from the projects to us, and that will in turn be available for debt service obligations, investments in internal or external growth opportunities or funding of our operations. There is a risk of equipment failure due to wear and tear, more frequent and/or larger than forecasted downtimes for equipment maintenance and repair, unexpected construction delays, latent defect, design error or operator error, or force majeure events, among other things, which could adversely affect revenues and cash flow. Additionally, older equipment, even if maintained in accordance with good practices, is subject to operational failure, including events that are beyond our control, and may require unplanned expenditures to operate efficiently. Unplanned outages of generation facilities, including extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues or require us to incur significant costs as a result of obtaining replacement power from third parties in the open market to satisfy our obligations.

In general, our power generation projects transmit electric power to the transmission grid for purchase under the PPAs through a single step up transformer. As a result, the transformer represents a single point of vulnerability and may exhibit no abnormal behavior in advance of a catastrophic failure that could cause a temporary shutdown of the facility until a replacement transformer can be found or manufactured. To the extent that we suffer disruptions of plant availability and power generation due to transformer failures or for any other reason, there could be a material adverse effect on our business, results of operations and financial condition and the amount of available cash flow may be adversely affected.

We provide letters of credit under our $200 million Revolving Credit Facility for contractual credit support at some of our projects. If the projects fail to perform under the related project-level agreements, the letters of credit could be drawn and we would be required to reimburse our senior lenders for the amounts drawn.

***The effects of weather and climate change may adversely impact our business, results of operations and financial condition***

Our operations are affected by weather conditions, which directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Conversely, moderate temperatures in winter or summer decrease heating or cooling electricity and gas demand and revenues. To the extent that weather is warmer in the summer or colder in the winter than assumed, we may require greater resources to meet our contractual commitments. These conditions, which cannot be accurately predicted, may have an adverse effect on our business, results of operations and financial condition by causing us to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

To the extent climate change contributes to the frequency or intensity of weather-related events, our operations and planning process could be impacted, which may adversely impact our business, results of operations and financial condition.

***Revenues from hydropower projects are highly dependent on precipitation and associated weather conditions and in the absence of such suitable conditions, our hydropower projects may not meet anticipated production levels, which could adversely affect our forecasted revenues***

We own interests in four hydropower projects, which are subject to substantial resource risks. The energy and revenues generated at a hydro energy project are highly dependent on precipitation patterns, which are variable and difficult to predict for any given year. We base our investment decisions with respect to each hydro energy project on the historical stream flow records for the area. However, actual climatic conditions in any given year may not meet the historical averages which would impair our ability to meet anticipated production levels, which could adversely affect our forecasted revenues.

***U.S., Canadian and/or global economic conditions and uncertainty could adversely affect our business, results of operations and financial condition***

Our business may be affected by changes in U.S., Canadian and/or global economic conditions, including inflation, deflation, interest rates, availability of capital, consumer spending rates and the effects of governmental initiatives to manage economic conditions. Uncertainty about global economic conditions may cause consumers to alter behaviors that may directly or indirectly reduce energy spending, which could have a material adverse effect on demand for our product. Volatility in the financial markets and the deterioration of national and global economic conditions may have a material adverse effect on our business, results of operations and financial condition.

Financial markets can also be, and have been in the past, affected by concerns over U.S. fiscal policy, federal deficit and related budget and tax issues. These concerns continue to raise discussions relating to the stability of the long-term sovereign credit rating of the United States. Any actions taken by the U.S. federal government regarding the federal deficit or any action taken or threatened by ratings agencies, could significantly impact the global and U.S. economies and financial markets. Any such economic downturn could have a material adverse effect on our business, results of operations and financial condition.

***Economic and political developments in the United States, including as they relate to the North American Free Trade Agreement, could adversely affect our business, results of operations and financial condition***

Officials in the new U.S. presidential administration and other policy makers have suggested renegotiations of the North American Free Trade Agreement ("NAFTA") and other international trade agreements and the implementation of tariffs, border taxes, border controls and other immigration restrictions, or other measures that could impact the level of trade and mobility between the United States and Canada. At the present time, it remains unclear what specific proposals may be implemented and the extent to which trade and/or border mobility between the United States and Canada would be affected, nor is the long-term impact of proposed reforms (including future reforms that may be part of any enacted reform) on the broader U.S. and Canadian economies clear. Given that we operate plants in both the United States and Canada, our business could be affected should the United States adopt trade or border control policies to restrict trade and/or mobility between the United States and Canada, but it is impossible at the present time to assess what this impact would be. As of February 27, 2018, renegotiations between the United States, Canada and Mexico were ongoing.

***Risks that are beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition***

Man-made events, such as acts of terror and governmental responses to acts of terror, could adversely affect general economic conditions, which could have a material impact on our business, results of operations and financial condition. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Our projects may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of the ability of the projects to generate and/or transmit electricity. Any such environmental repercussions or other disruption could result in a decline in energy consumption and significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our business, results of operations and financial condition.

Our projects could also be impacted by natural disasters, such as earthquakes, floods, lightning activity, hurricanes, tropical storms, winter storms, tornadoes, wind, seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive or otherwise disrupt our operations or compromise the physical or cyber security of our facilities, which could result in increased costs and could adversely affect our ability to manage our business effectively. We maintain standard insurance against catastrophic losses, which are subject to deductibles, limits and exclusions; however, our insurance coverage may not be sufficient to cover all of our losses. Additionally, future significant weather-related events, natural disasters and other similar events that have an adverse effect on the economy could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition.

***Our business faces significant operating hazards, natural disaster risks and other hazards such as fire and explosions and insurance may not be sufficient to cover all losses***

Our business involves significant operating hazards related to the generation of electricity, including hazards related to acquiring, transporting and unloading fuel, operating large pieces of rotating equipment, structural collapse, machinery failure, and delivering electricity to transmission and distribution systems. In addition, we are exposed to natural disaster risks and other hazards such as fire and explosions. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, disruption of communication systems and technology, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being subject to various litigation matters, including regulatory and administrative proceedings, asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. While we believe that the projects maintain an amount of insurance coverage that is adequate and similar to what would be maintained by a prudent owner/operator of similar facilities, and are subject to deductibles, limits and exclusions which are customary or reasonable given the cost of procuring insurance, current operating conditions and insurance market conditions, there can be no assurance that such insurance will continue to be offered on an economically feasible basis, nor that all events that could give rise to a loss or liability are insurable or insured, nor that the amounts of insurance will at all times be sufficient to cover each and every loss or claim that may occur involving our assets or operations of our projects. Any losses in excess of those covered by insurance, which may include a significant judgment against any project or project operator, the loss of a significant permit or other approval or the imposition of a significant fine or penalty, could have a material adverse effect on our business, results of operations, financial condition and future prospects.

***Our operations are subject to the provisions of various energy laws and regulations***

Our business is subject to extensive Canadian and U.S. federal, state, provincial and local laws and regulations. Compliance with the requirements under these various regimes may cause us to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of the non-complying facility, the imposition of liens, fines and/or civil or criminal liability.

Generally, in the United States, our projects are subject to regulation by the FERC regarding the terms and conditions of wholesale service and rates, as well as by state regulators regarding the prudency of utilities entering into PPAs entered into by QF projects and the siting of the generation facilities. The majority of our generation is sold by QF projects under PPAs that required approval by state authorities.

The EP Act of 2005 also limited the requirement that electric utilities buy electricity from QFs in certain markets that have certain competitive characteristics, potentially making it more difficult for our current and future projects to negotiate favorable PPAs with these utilities.

If any project were to lose its status as a QF, it would lose its ability to make sales to utilities on favorable terms. Such project may no longer be entitled to exemption from provisions of the Public Utility Holding Company Act of 2005 or from certain provisions of the Federal Power Act and state law and regulations. Loss of QF status could also trigger defaults under covenants to maintain that status in the PPAs and project-level debt agreements, and if not cured within allowed cure periods, could result in termination of agreements, penalties or acceleration of indebtedness under such agreements. In such event, our business, results of operations and financial condition could be negatively impacted.

Notwithstanding their status as QFs and EWGs, our facilities remain subject to numerous FERC regulations, including those relating to power marketer status, approval of mergers, acquisitions and investments relating to utilities, and mandatory reliability rules and regulations delegated to NERC. Any violation of these rules and regulations could subject us to significant fines and penalties and negatively impact our business, results of operations and financial condition.

The EP Act of 2005 and other federal and state programs also may provide incentives for various forms of electric generation technologies, which may subsidize our competitors. The U.S. regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale competition and the creation of incentives for the addition of large amounts of new renewable energy generation and, in some cases, transmission. These changes are ongoing and we cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on our business. In addition, in some of these markets, interested parties have proposed material market design changes, including the elimination of a single clearing price mechanism as well as proposals to re-regulate the markets. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric power markets is reversed, discontinued, or delayed, or new law or other future regulatory developments are introduced, our business, results of operations and financial condition could be negatively impacted.

Generally, in Canada, our projects are subject to energy regulation primarily by the relevant provincial authorities. In addition, our projects are subject to Canada's corporate, commercial and other laws of general application to businesses. Our projects require licenses, permits and approvals which can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with and renew, as required, all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable licenses, permits and approvals, our business, results of operations and financial condition could be adversely affected.

The introductions of new laws, or other future regulatory developments, may have a material adverse impact on our business, operations or financial condition.

Risks with respect to the two Canadian provinces where we currently have projects are addressed further below.

*British Columbia*

The Government of British Columbia has a number of specific statutes and regulations that govern the generation, transmission and distribution of electricity within British Columbia. Our projects in that province are subject to these laws. These statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

The *Utilities Commission Act* governs the BCUC, which is responsible for the regulation of British Columbia's public energy utilities, which include publicly owned and investor-owned utilities (i.e., independent power producers). All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the BCUC as being "in the public interest." The BCUC may hold a hearing in this regard. Furthermore, the BCUC may make rules governing conditions to be contained in agreements entered into by public utilities for electricity. Consequently, power procurement is controlled by the BCUC and, as a result, our potential contracts with BC Hydro may be subject to terms that adversely affect us.

The *Clean Energy Act* sets out British Columbia's energy objectives, one of which is the generation of at least 93% of the electricity in British Columbia from clean or renewable resources. BC Hydro is required to submit for review and approval every five years to the Government of British Columbia resource plans outlining how it will meet these objectives. BC Hydro is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers. Two of our three British Columbia projects currently sell all of their electricity to BC Hydro, and the third project sells substantially all of its electricity to BC Hydro. Therefore, changes to BC Hydro's energy procurement policies and financial difficulties of or regulatory intervention in respect of BC Hydro and/or the province's energy objectives could impact the market for electricity generated by our British Columbia projects, although BC Hydro is currently limited by regulation to undertaking efficiency improvements at its existing facilities and undertaking development of new generation facilities/projects only with BCUC approval. There is a risk that the regulatory regime could adversely affect the amount of power that BC Hydro purchases from our projects and the competitive environment or the price at which BC Hydro is willing to purchase power from our British Columbia projects.

*Ontario*

The government of Ontario has a number of specific statutes and regulations that govern our projects in that province. The statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

In Ontario, the OEB is an administrative tribunal with authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects. No person is permitted to own or operate a large or medium-scale electricity generation facility in Ontario without a license from the OEB. Although all of our Ontario projects are currently licensed, the OEB has the authority to effectively modify the licenses by adopting “codes” that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in fines.

Although the OEB provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the OEB, and the OEB is required to implement such policy directives. Thus, the OEB’s regulation of our projects is subject to potential political interference, to a degree.

A number of other regulators and quasi-governmental entities play a role, including the IESO, Hydro One, the ESA and OEFC. All these agencies may affect our projects.

***Noncompliance with federal reliability standards may subject us and our projects to penalties***

Many of our operations are subject to the regulations of NERC, a self-regulatory non-governmental organization which has statutory responsibility to regulate bulk power system users and generation and transmission owners and operators. NERC groups the users, owners, and operators of the bulk power system into 17 categories, known as functional entities—e.g., Generator Owner, Generator Operator, Purchasing-Selling Entity, etc.—according to the tasks they perform. The NERC Compliance Registry lists the entities responsible for complying with federal mandatory reliability standards and the FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity found to be in noncompliance. Violations may be discovered or identified through self-certification, compliance audits, spot checking, self-reporting, compliance investigations by NERC (or a regional reliability organization) and the FERC, periodic data submissions, exception reporting, and complaints. The penalty that could be imposed for violating the requirements of the standards is a function of the Violation Risk Factor. Penalties for the most severe violations can reach as high as $1 million per violation, per day, and our projects could be exposed to these penalties if violations occur, which could have a material adverse effect on our business, results of operations and financial condition.

***Our projects are subject to significant environmental and other regulations***

Our projects are subject to numerous and significant federal, state, provincial and local laws, including statutes, regulations, by-laws, guidelines, policies, directives and other requirements governing or relating to, among other things: air emissions; discharges into water; ash disposal; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and off site; land use and zoning matters; and workers’ health and safety matters. Our facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, penalties and property damage. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential civil actions, compliance or remediation orders, fines and other penalties), and may result in the projects being involved from time to time in administrative and judicial proceedings relating to such matters. We have implemented environmental, health and safety management programs designed to regularly improve environmental, health and safety performance, but there is no guarantee that such programs will fully and effectively eliminate the inherent risk of environmental, health and safety liabilities related to the operation of our projects.

Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In the United States, the Clean Air Act and related regulations and programs of the Environmental Protection Agency extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds by power plants. In July 2011, the EPA issued its final Cross-State Air Pollution Rule ("CSAPR"), which replaces its prior Clean Air Interstate Rule and requires 27 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through participation in a cap and trade system or more aggressive state-by-state emissions limits. In November 2014, the EPA issued a ministerial rule setting a schedule for implementation of the CSAPR beginning in 2015, and in September 2016, the EPA issued the CSAPR Update Rule, intended to implement the 2008 ozone national air quality standards by requiring further reductions in nitrogen oxides in 2017 in 23 states subject to CSAPR during the summertime ozone season. Other more stringent EPA air emission regulations being implemented include the more stringent national ambient air quality standards for sulfur dioxide, issued in June 2010; for fine particulate matter, issued in December 2012; and for ozone, issued in October 2015. In the case of the ozone standard, however, EPA has extended the implementation deadline, the standard is subject to potential legislative modification and judicial challenge that is stayed while the Trump administration reconsiders the standard. Additionally, the EPA's mercury and air toxics emissions standards for power plants ("MATS"), first issued in December 2011, underwent court-mandated reconsideration and revision in 2015 and 2016 and are beginning to go into effect. Judicial challenges to the MATS regulation are in abeyance while the Trump administration decides whether it should be "maintained, modified or otherwise reconsidered." Meeting these new standards, when implemented, may have a material adverse impact on our business, results of operations and financial condition.

In December 2014, the EPA issued its final regulations governing disposal of coal ash in landfills and impoundments. The final rule affirmed the historic treatment of coal ash as non-hazardous solid waste but establishes new requirements governing structural integrity, groundwater protection, operating criteria, recordkeeping and reporting, and closure for such landfills and impoundments. We are currently assessing the increased compliance obligations and associated costs to our 40% owned coal-fired facility.

Similar increasingly stringent environmental regulations also apply to our projects in British Columbia and Ontario.

Significant costs may be incurred for either capital expenditures or the purchase of allowances under any or all of these programs to keep the projects compliant with environmental laws and regulations. Some of our projects' PPAs do not allow for the pass-through of emissions allowance or emission reduction capital expenditure costs. If it is not economical to make those expenditures, it may be necessary to retire or mothball facilities, or restrict or modify our operations to comply with more stringent standards.

Our projects have obtained environmental permits and other approvals that are required for their operations. Compliance with applicable environmental laws, regulations, permits and approvals and material future changes to them could materially impact our businesses. Although we believe the operations of the projects are currently in material compliance with applicable environmental laws, licenses, permits and other authorizations required for the operation of the projects, and although there are environmental monitoring and reporting systems in place with respect to all the projects, there is no guarantee that more stringent laws will not be imposed, that there will not be more stringent enforcement of applicable laws or that such systems may not fail, which may result in material expenditures. Failure by the projects to comply with any environmental, health or safety requirements, or increases in the cost of such compliance, including as a result of unanticipated liabilities or expenditures for investigation, assessment, remediation or prevention, could result in additional expense, capital expenditures, restrictions and delays in the projects' activities, the extent of which cannot be predicted and which could have a material adverse effect on our business, results of operations and financial condition.

***If additional regulatory requirements are imposed on energy companies mandating limitations on greenhouse gas emissions or requiring efficiency improvements, such requirements may result in compliance costs that alone or in combination could make some of our projects uneconomical to maintain or operate***

The EPA, other regulatory agencies, environmental advocacy groups and other organizations are focusing considerable attention on greenhouse gas emissions from power generation facilities and their potential role in climate change. See “Item 1. Business—Industry Regulation—Carbon Emissions.”

There are also potential impacts on our natural gas businesses as greenhouse gas legislation or regulations may require greenhouse gas emission reductions from the natural gas sector and could affect demand for natural gas. Additionally, greenhouse gas requirements could result in increased demand for energy conservation and renewable products, as well as increase competition surrounding such innovation. Additionally, our reputation could be damaged due to public perception surrounding greenhouse gas emissions at our power generation projects. Any such negative public perception could ultimately result in a decreased demand for electric power generation or distribution. Several regions of the United States and Canada have moved forward with greenhouse gas emission regulation.

Concerning our projects in British Columbia, regulatory restrictions stemming from the GGIRTA and the GGRCTA, and financial commitments arising in connection with the requirements under the CTA, could affect our ability to operate our projects in British Columbia and affect our profitability. Concerning our projects in Ontario, the Ontario Cap and Trade Act and the Cap and Trade Program, from the beginning of 2017, increased the cost of generating electricity using natural gas and the price of the electricity produced by our natural gas-powered projects in the Province. In addition, on December 15, 2016, the IESO entered into an electricity trade agreement with Hydro-Québec under which the IESO will purchase a total of 14 terawatt hours (TWh) of electricity from Hydro-Québec over a seven-year period from 2017 to 2023. The News Release issued by the Government of Ontario regarding this agreement stated that “Ontario will reduce the cost to its consumers by $70 million compared to its previous plan by importing 2 TWh of hydroelectric power each year from Québec to replace the use of natural gas.” As stated above, we ceased producing electricity using natural gas in Ontario at the end of 2017 and anticipate that the increasing carbon price and other initiatives to reduce greenhouse gas emissions associated with the generation of electricity in the Province could affect our ability to operate our projects in Ontario and affect our profitability, but note that there will be a provincial election in Ontario in 2018 and that the future of the current cap and trade system for GHG emissions is now uncertain.

All of our subject generating facilities have complied on a timely basis with the new EPA and Ontario greenhouse gas reporting requirements. Compliance with greenhouse gas emission reduction requirements may require increasing the energy efficiency of equipment at our natural gas projects, purchase of allowances and/or offsets, fuel switching, and/or retirement of high-emitting projects and potential replacement with lower emitting projects. The cost of compliance with greenhouse gas emission legislation and/or regulation is subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon capture and storage technology, the selected compliance alternatives and in the United States the actions taken by the Trump Administration to revoke Obama era climate regulations. We cannot estimate the aggregate effect of such requirements on our business, results of operations, financial condition or our customers. However, such expenditures, if material, could make our generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect our business, results of operations and financial condition.

***Impairment of goodwill, long-lived assets or equity method investments could have a material adverse effect on our results of operations and financial condition***

As of December 31, 2017, we had $21.3 million of goodwill, which represented approximately 1.8% of our total assets on our consolidated balance sheets. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if an event or change in circumstance occurs that would more likely than not reduce the fair value of a reporting unit below its carrying value. We could be required to, and have in the past, evaluated the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to, sustained declines in market capitalization, deterioration in general economic conditions or our operating or regulatory environment, increased competitive environment, an increase in fuel costs (particularly when we are unable to pass-through the impact to customers), significant changes in forecasted market prices for power, negative or declining cash flows, loss of a key contract or customer (particularly when we are unable to replace it on equally favorable terms), our inability to renew certain of our PPAs following their expiration or termination (for a description of the status of these agreements and related renegotiations, see Item 1A. Risk Factors - The expiration or termination of our PPAs could have a material adverse impact on our business, results of operation and financial condition), divestiture of a significant component of our business or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if any acquisitions we make do not perform as expected. See Note 8 to the consolidated financial statements included in this Annual Report on Form 10-K.

Long-lived assets are initially recorded at acquisition cost and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above.

We have recorded $187.2 million, $85.9 million and $127.8 million of goodwill, long-lived asset and equity method investment impairments for the years ended December 31, 2017, 2016 and 2015, respectively.

***Failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002 could negatively affect our business, market confidence in our reported financial information, and the price of our common stock.***

We continue to document, test, and monitor our internal controls over financial reporting in order to satisfy all of the requirements of Section 404 of the Sarbanes-Oxley Act of 2002; however, we cannot be assured that our disclosure controls and procedures and our internal controls over financial reporting will prove to be completely adequate in the future. Failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002 could negatively affect our business, market confidence in our reported financial information, and the price of our common stock.

***Increasing competition could adversely affect our performance and the performance of our projects***

The power generation industry is characterized by intense competition and our projects encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for PPAs, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins.

Further, changes and developments in technology, including fuel cells, microturbines, solar cells and other emerging technologies related to energy generation, distribution and consumption, may facilitate the entrance of new competitors, increase the supply of electricity, and reduce the cost of methods of producing power that we do not currently use or lower the price of or demand for energy. If these technologies became cost competitive, we could face increasing competition and the value of our generating facilities could be reduced.

In addition, we continue to confront significant competition for acquisition and investment opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms, if at all. Increasing competition among participants in the power generation industry may adversely affect our performance and the performance of our projects. Further, a payout of a significant portion of our cash flow to service our debt may result in us not retaining a sufficient amount of cash to finance acquisition or investment opportunities and make other capital and operating expenditures. See "—Risk Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities."

***We have limited control over management decisions at certain projects***

Four of our projects are not wholly-owned by us or we have contracted for their operations and maintenance, and in some cases we have limited control over the operation of the projects. Although we generally prefer to acquire projects where we have control, we may make acquisitions in non-control situations to the extent that we consider it advantageous to do so and consistent with regulatory requirements and restrictions, including the Investment Company Act of 1940. Third-party operators operate four of our projects. As such, we must rely on the technical and management expertise of these third-party operators, although typically we negotiate to obtain positions on a management or operating committee if we do not own 100% of a project. To the extent that such third-party operators do not fulfill their obligations to manage the operations of the projects or are not effective in doing so, our cash flow may be adversely affected. The approval of third-party operators also may be required for us to receive distributions of funds from projects or to transfer our interest in projects. Our inability to control fully certain projects could have an adverse effect on our business, results of operations and financial condition.

***We may face significant competition for acquisitions and may not be able to finance or otherwise pursue, execute or successfully integrate acquisitions or new business initiatives***

To the extent identification of and pursuit of acquisition opportunities forms a part of our strategy, we may be unable to identify attractive acquisition candidates in the power industry in the future, and we may not be able to make acquisitions on an accretive basis or at all, or be sure that such acquisitions, if any, will be successfully integrated into our existing operations. In addition, a payout of a significant portion of our cash flow to service our debt obligations, may result in us not retaining a sufficient amount of cash to finance any acquisition or other growth opportunities, to the extent any such acquisition or other opportunities are available to us. As a result, we may have to forego such opportunities, even if they would otherwise be necessary or desirable, if we do not find alternative sources of financing for such opportunities to make cash available to us. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors.

Although electricity demand is expected to grow, creating the need for more generation, such growth is expected to occur at a slower rate. The U.S. power industry is continuing to undergo consolidation and may present attractive acquisition opportunities but we are likely to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments.

Any acquisition, investment or new business initiative may involve potential risks, including an increase in indebtedness, the inability to successfully integrate operations, the potential disruption of our ongoing business, the diversion of management's attention from other business concerns, inadequate return on capital and the possibility that we pay more than the acquired company or interest is worth. There may also be liabilities that we fail to discover, or are unable to discover, in our due diligence prior to the consummation of an acquisition or prior to launching an initiative or entering a market. We may not be indemnified for some or all of these liabilities in an acquisition transaction.

***Our equity interests in certain projects may be subject to transfer restrictions***

The partnership or other agreements governing some of the projects may limit a partner's ability to sell its interest. Specifically, these agreements may prohibit any sale, pledge, transfer, assignment or other conveyance of the interest in a project without the consent of the other partners. In some cases, other partners may have rights of first offer or rights of first refusal in the event of a proposed sale or transfer of our interest. These restrictions may limit or prevent us from managing our interests in these projects in the manner we see fit, and may have an adverse effect on our ability to sell our interests in these projects at the prices we desire. See "—Risks Related to Our Structure—We cannot provide any assurance regarding the outcome or impact on our business of any potential options we are considering."

***Our projects are exposed to risks inherent in the use of derivative instruments***

We and our projects may use derivative instruments, including futures, forwards, options and swaps, to manage commodity and financial market risks. These activities, though intended to mitigate price volatility, expose us to other risks. In the future, the project operators could recognize financial losses on these arrangements, including as a result of volatility in the market values of the underlying commodities, if a counterparty fails to perform under a contract or upon the failure or insolvency of a financial intermediary, exchange or clearinghouse used to enter, execute or clear the transactions. If actively quoted market prices and pricing information from external sources are not available, the valuation of these contracts would involve judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Most of these contracts are recorded at fair value with changes in fair value recorded currently in the statement of operations, resulting in significant volatility in our income (loss) (as calculated in accordance with GAAP) that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. As a result, we may be unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual income (loss) (as calculated in accordance with GAAP).

If the values of these financial contracts change in a manner that we do not anticipate, or if a counterparty fails to perform under a contract, it could harm our business, results of operations, financial condition and cash flows. We have executed natural gas swaps to reduce our risks to changes in the market price of natural gas, which is the fuel consumed at many of our projects. Due to decreases in natural gas prices, we have incurred losses on these natural gas swaps. We execute these swaps only for the purpose of managing risks and not for speculative trading.

We do not typically hedge the entire exposure of our operations against commodity price volatility. To the extent we do not hedge against commodity price volatility, our business, results of operations and financial condition may be improved or diminished based upon movement in commodity prices.

***Certain employees are subject to collective bargaining***

A number of our plant employees, at one plant in British Columbia and at four plants in Ontario, are subject to collective bargaining agreements. These agreements expire periodically and we may not be able to renew them without a labor disruption or without agreeing to significant increases in labor costs. Strikes, work stoppages or the inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on our business, results of operations and financial condition.

***Our Pension Plan may require additional future contributions***

Certain of our employees in Canada are participants in a defined benefit pension plan that we sponsor. The additional amount of future contributions to our defined benefit plan will depend upon asset returns and a number of other factors and, as a result, the amounts we will be required to contribute in the future may vary. Cash contributions to the plan will reduce the cash available for our business.

***Hostile cyber intrusions could severely impair our operations, lead to the disclosure of confidential information, damage our reputation and otherwise have an adverse effect on our business, results of operations and financial condition***

A cyber intrusion is considered to be any adverse event that threatens the confidentiality, integrity or availability of our information resources. More specifically, a cyber intrusion is an intentional attack or an unintentional event that can include gaining unauthorized access to systems to disrupt operations, corrupt data, steal confidential information, and impact our ability to make collections or otherwise impact our operations. We are dependent on various information technologies throughout our company and our projects to carry out multiple business activities. Further, the computer systems that run our facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. and/or Canadian bulk power system or our operations could view our computer systems, software or networks as attractive targets for cyber attack. In addition, our business requires that we collect and maintain confidential employee and shareholder information, which is subject to the risk of electronic theft or loss.

A successful cyber attack, such as unauthorized access, malicious software or other violations on the systems that control generation and transmission at our projects could severely disrupt business operations, diminish competitive advantages through reputation damages and increase operational costs. The breach of certain business systems could affect our ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For these reasons, a significant cyber incident could materially and adversely affect our business, results of operations and financial condition.

***Failure to comply with the U.S. Foreign Corrupt Practices Act and/or the Canadian Corruption of Foreign Public Officials Act could subject us to, among other things, penalties and legal expenses that could harm our reputation and have a material adverse effect on our business, results of operations and financial condition***

We are subject to anti-corruption laws and regulations including the U.S. Foreign Corrupt Practices Act ("FCPA") and the Canadian Corruption of Foreign Public Officials Act (the "CFPOA"), which generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or keeping business and/or other benefits. In addition, the FCPA imposes accounting standards and requirements on U.S. publicly traded corporations and their foreign affiliates, which are intended to prevent the diversion of corporate funds to the payment of bribes and other improper payments, and to prevent the establishment of "off books" slush funds from which improper payments can be made (similar provisions have been proposed to be added to the CFPOA). The Securities and Exchange Commission has increased its enforcement of the FCPA during the past several years. In recent years, enforcement of the CFPOA in Canada has also increased and can be attributed, in part, to the establishment of the Royal Canadian Mounted Police's International Anti-Corruption Unit in 2008. Although we have implemented policies and procedures designed to ensure that we, our employees and other intermediaries comply with the FCPA and/or the CFPOA, there is no assurance that such policies or procedures will work effectively all of the time or protect us against liability under the FCPA and/or the CFPOA for actions taken by our employees and other intermediaries with respect to our business or any businesses that we may acquire. If we are not in compliance with the FCPA and/or the CFPOA, we may be subject to criminal penalties pursuant to the CFPOA and/or criminal and civil penalties and other remedial measures pursuant to the FCPA, including changes or enhancements to our procedures, policies and control, as well as potential personnel change and disciplinary actions, which could have an adverse impact on our business, results of operations and financial condition.

***Our success depends in part on our ability to retain, motivate and recruit executives and other key employees, and failure to do so could negatively affect us***

Our success depends in part on our ability to retain, recruit and motivate key employees who have experience in our industry. Experienced employees in the power industry are in high demand and competition for their talents can be intense. Further, an aging work force in the power industry necessitates recruiting, retaining and developing the next generation of leadership. A failure to attract and retain executives and other key employees with specialized knowledge in power generation could have an adverse impact on our business, results of operations and financial condition because of the difficulty of promptly finding qualified replacements. See "—Risks Related to our Structure—Our recent management changes may impact our business plan."

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

We have included descriptions of the locations and general character of our principal physical operating properties, including an identification of the segments that use such properties, in "Item 1. Business," which is incorporated herein by reference. A significant portion of our equity interests in the entities owning these properties is pledged as collateral under our Credit Facilities or under non-recourse operating level debt arrangements.

Our principal executive office is located at 3 Allied Drive Suite 220, Dedham, Massachusetts under a lease that expires in 2024.

## ITEM 3. LEGAL PROCEEDINGS

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of December 31, 2017.

## ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

## PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

### Purchases of Equity Securities by the Issuer and Affiliated Purchasers

### Share Repurchase Program

On December 29, 2017, we commenced a Normal Course Issuer Bid ("NCIB") for each of our Series C and Series D Debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd. ("APPEL"), our wholly-owned subsidiary. The NCIBs expire on December 28, 2018 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the new NCIBs. Under the NCIB, we may purchase up to a total of 11,308,946 common shares based on 10% of our public float as of December 15, 2017 and we are limited to daily purchases of 11,789 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the New York Stock Exchange in compliance with rule 10b-18 under the U.S. Securities Exchange Act of 1934, as amended, or other designated exchanges and published marketplaces in the U.S. in accordance with applicable regulatory requirements. The ability to make certain purchases through the facilities of the NYSE is subject to regulatory approval.

### Market Information and Holders

Our common shares trade on the NYSE under the symbol "AT" and on the TSX under the symbol "ATP".

The following table sets forth the price ranges of our outstanding common shares, as reported by the NYSE for the periods indicated:

| Period | High (US$) | Low (US$) |
|---|---|---|
| Quarter ended December 31, 2017 | 2.58 | 2.35 |
| Quarter ended September 30, 2017 | 2.50 | 2.30 |
| Quarter ended June 30, 2017 | 2.70 | 2.30 |
| Quarter ended March 31, 2017 | 2.70 | 2.25 |
| Quarter ended December 31, 2016 | 2.75 | 2.13 |
| Quarter ended September 30, 2016 | 2.67 | 2.33 |
| Quarter ended June 30, 2016 | 2.75 | 2.21 |
| Quarter ended March 31, 2016 | 2.58 | 1.58 |

The following table sets forth the price ranges of our common shares, as applicable, as reported by the TSX for the periods indicated:

| Period | High (Cdn$) | Low (Cdn$) |
|---|---|---|
| Quarter ended December 31, 2017 | 3.29 | 2.96 |
| Quarter ended September 30, 2017 | 3.19 | 2.87 |
| Quarter ended June 30, 2017 | 3.62 | 3.05 |
| Quarter ended March 31, 2017 | 3.60 | 2.97 |
| Quarter ended December 31, 2016 | 3.67 | 2.88 |
| Quarter ended September 30, 2016 | 3.49 | 3.05 |
| Quarter ended June 30, 2016 | 3.49 | 2.85 |
| Quarter ended March 31, 2016 | 3.36 | 2.21 |

The number of common shares outstanding was 116,008,834 on February 27, 2018.

**Securities Authorized for Issuance under Equity Compensation Plans**

The following table provides information as of December 31, 2017 regarding our Long-Term Incentive Plan. For the description of our Long-Term Incentive Plan, see Note 16, *Equity Compensation Plans* to the consolidated financial statements.

| | Number of securities to be issued upon exercise of outstanding options, warrants and rights[(1)(2)] (a) | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))[(1)(2)] (c) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 1,923,049 | $ — | 1,295,476 |
| Equity compensation plans not approved by security holders | 359,936 | — | 240,064 |
| Total | 2,282,985 | $ — | 1,535,540 |

(1) Number of securities to be issued upon exercise of outstanding awards and number of securities remaining available for future issuance reflects expected redemption of award one-third in cash and two-thirds in common shares. See Item 15. "Exhibits and Financial Statements Schedule"—Note 2(u), Equity compensation plans.

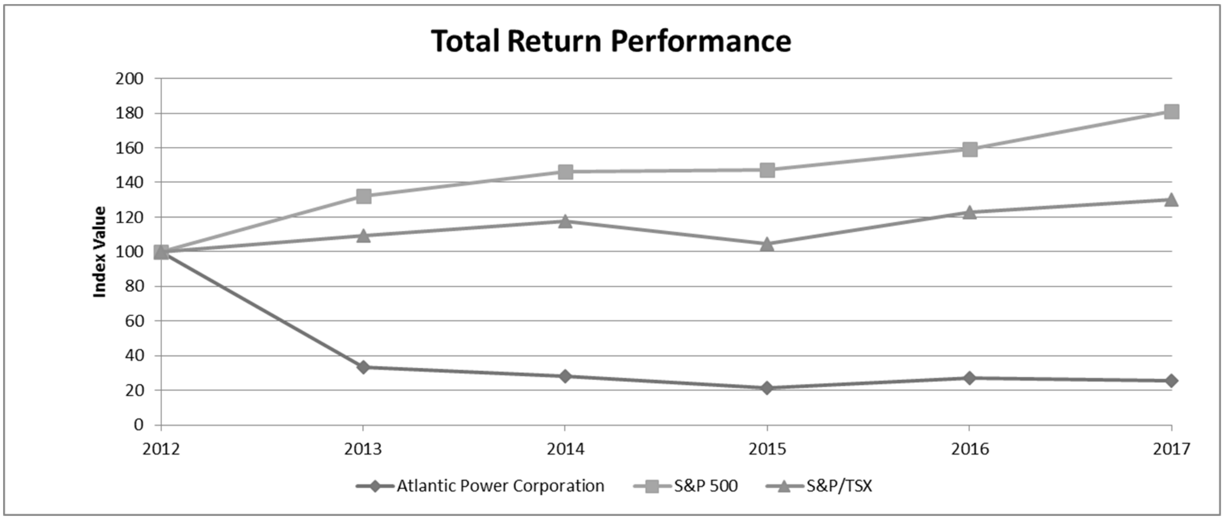
(2) The maximum aggregate number of common shares that may be issued under our Long-Term Incentive Plan upon redemption of notional shares is 6,000,000 and the maximum aggregate number of common shares that may be issued under our Transition Equity Grant Participation Agreement upon redemption of notional shares is 600,000. See Item 15. "Exhibits and Financial Statements Schedule"—Note 2(u), Equity compensation plans.

**Performance Graph**

The performance graph below compares the cumulative total shareholder return on our common shares for the period December 31, 2012, through December 31, 2017, with the cumulative total return of the Standard & Poor's 500 Composite Stock Price Index, or S&P 500, and the Standard & Poor's TSX Composite, or S&P/TSX. Our common shares trade on the NYSE under the symbol "AT" and the TSX under the symbol "ATP".

The performance graph shown below is being furnished and compares each period assuming that a $100 investment was made on December 31, 2012, in each of our common shares, the stocks included in the S&P 500 and the stocks included in the S&P/TSX, and that all dividends were reinvested.

**Comparison of Cumulative Total Return**




| | Dec-2012 | Dec-2013 | Dec-2014 | Dec-2015 | Dec-2016 | Dec-2017 |
|---|---|---|---|---|---|---|
| AT | $ 100.00 | $ 33.36 | $ 28.32 | $ 21.39 | $ 27.15 | $ 25.52 |
| S&P | 100.00 | 132.39 | 146.08 | 147.46 | 159.42 | 181.25 |
| S&P / TSX | 100.00 | 109.55 | 117.69 | 104.64 | 122.95 | 130.37 |

## ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial information for each of the periods indicated. The annual historical information for each of the years in the three-year period ended December 31, 2017 has been derived from our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

You should read the following selected consolidated financial data along with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and the accompanying notes, which describe the impact of material acquisitions and dispositions that occurred in the three-year period ended December 31, 2017.

| (in millions of U.S. dollars, except as otherwise stated) | Year Ended December 31, 2017[(a)] | 2016[(a)] | 2015[(a)(b)] | 2014[(a)(b)(c)(d)] | 2013[(a)(b)(c)(d)(e)] |
|---|---|---|---|---|---|
| Project revenue | $ 431.0 | $ 399.2 | $ 420.2 | $ 489.9 | $ 473.4 |
| Project (loss) income | (47.4) | 10.1 | (41.4) | (38.9) | 45.0 |
| Loss from continuing operations | (93.0) | (113.9) | (84.1) | (153.2) | (23.6) |
| Income (loss) from discontinued operations, net of tax | — | — | 19.5 | (29.0) | (0.2) |
| Net loss attributable to Atlantic Power Corporation | (98.6) | (122.4) | (62.4) | (177.4) | (33.0) |
| Basic and diluted (loss) income per share[(f)] | | | | | |
| Loss per share from continuing operations attributable to Atlantic Power Corporation | $ (0.86) | $ (1.02) | $ (0.76) | $ (1.37) | $ (0.30) |
| Income (loss) from discontinued operations, net of tax | — | — | 0.25 | (0.10) | 0.02 |
| Net loss attributable to Atlantic Power Corporation | $ (0.86) | $ (1.02) | $ (0.51) | $ (1.47) | $ (0.28) |
| Per common share dividend declared | $ — | $ — | $ 0.09 | $ 0.29 | $ 0.54 |
| Total assets | $ 1,158.8 | $ 1,456.8 | $ 1,671.2 | $ 2,853.2 | $ 3,353.3 |
| Total long-term liabilities | $ 829.1 | $ 1,020.0 | $ 1,020.0 | $ 1,656.6 | $ 1,867.9 |

(a) Includes $187.2 million, $85.9 million, $127.8 million, $106.6 million and $34.9 million of goodwill, long-lived asset and equity method investment impairments for the years end December 31, 2017, 2016, 2015, 2014 and 2013, respectively.

(b) Excludes the Wind Projects, which are classified as discontinued operations for the years ended December 31, 2015, 2014 and 2013.

(c) Excludes Greeley, which is classified as discontinued operations for the years ended December 31, 2014 and 2013.

(d) The total assets exclude $62.8 million and $41.7 million of deferred financing costs for the years ended December 31, 2014 and 2013, respectively.

(e) Excludes the Florida Projects, Path 15 and Rollcast, which are classified as discontinued operations for the years ended December 31, 2013.

(f) Diluted (loss) earnings per share is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long-term incentive plan (“LTIP”). Please see the notes to our historical consolidated financial statements included elsewhere in this Form 10-K for information relating to the number of shares used in calculating basic and diluted earnings (loss) per share for the periods presented.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

*The following management's discussion and analysis of financial condition and results of operations should be read in conjunction with our audited consolidated financial statements included in this Annual Report on Form 10-K. All dollar amounts discussed below are in millions of U.S. dollars, unless otherwise stated. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").*

**(in millions of U.S. dollars, except per-share amounts)**

The discussion and analysis below has been organized as follows:

1) Our Strategy, Overview of 2017 Results and Recent Events
2) Consolidated Overview and Results of Operations
3) Project Operating Performance
4) Supplementary Non-GAAP Financial Information
5) Liquidity and Capital Resources
6) Critical Accounting Policies

### Our Strategy, Overview of 2017 Results and Recent Events

Management continues to be focused on the following priorities:

- *Debt reduction*: By strengthening our balance sheet we intend to improve our financial flexibility and become more competitive to pursue external growth opportunities.
- *PPA renewals*: We seek to leverage the strength of our operations, diversity and location of our projects to renew or extend expiring PPAs, or make alternative arrangements in a challenging market.
- *Capital allocation:* We will be rational in allocating our capital to balance risk and reward.
- *External growth*: We seek to take a creative, disciplined and value-oriented approach to external development or acquisitions.
- *Fleet optimization*: By making capital investments in or efficiency improvements to our existing projects we are able to achieve cash returns that are higher than what is currently available in the external markets and at lower risk.
- *Overhead cost control*: Improving our cost structure provides additional flexibility for debt reduction, external growth and other value-accretive investments.

In 2017, we continued to make progress in strengthening the Company. Our key achievements in the execution of our strategy during 2017 were:

- *Debt reduction*– During 2017, we made payments of $165.9 million to amortize our corporate and project-level debt, including a $54.6 million payment, in full, for Piedmont's non-recourse project-level debt. Piedmont will now be able to make cash distributions previously disallowed due to the terms of the project debt's covenants. Additionally, we were able to reprice the Term Loan Facilities twice during 2017, lowering the rate from LIBOR plus 5.00% to LIBOR plus 3.50%. This decrease is expected to save approximately $33 million of interest expense through maturity. As a result of our progress in reducing leverage and other factors, Moody's Investors Service ("Moody's) upgraded our Corporate Family Rating to Ba3 from B1 and the senior secured term loan and revolving credit facilities at APLP Holdings to Ba2 from Ba3 in October 2017.

- *Common and preferred share repurchases* - We utilized $3.3 million of our discretionary capital to repurchase and cancel common ($0.2 million) and preferred ($3.1 million) shares during 2017 with the goal of capturing price-to-value opportunities in the market.

- *Overhead cost reduction* – We cut our corporate overhead expense from approximately $54 million in 2013 to $23 million for 2016, which represents a cumulative reduction from 2013 of approximately 58%. In 2017, we maintained this expense at approximately 2016 levels.

- *Investment in our fleet* – During 2017 we invested $5.3 million in the optimization of our fleet, for a cumulative investment of approximately $25 million since 2013.

*Convertible Debenture Offering*

On January 29, 2018, we closed the Series E Debenture Offering of Cdn$100 million aggregate principal amount of Series E Debentures. We also granted the underwriters the option to purchase up to an additional Cdn$15 million aggregate principal amount of Series E Debentures at any time up to 30 days after the date of closing of the Series E Debenture Offering to cover over-allotments. The underwriters exercised that option for the full Cdn$15 million aggregate principal amount on February 2, 2018.

On the initial closing date, we received net proceeds from the Series E Debentures Offering, after deducting the underwriting fee and expenses, of approximately Cdn$94.7 million. We received an additional Cdn$14.4 million of net proceeds from the exercise of the over-allotment option. On January 29, 2018, we issued a notice to redeem all of the $42.5 million remaining principal amount of Series C Debentures with the use of a portion of the proceeds from the Series E Debenture Offering. On February 2, 2018, we issued a notice to redeem Cdn$56.2 million principal amount of the Series D Debentures with the remaining proceeds from the Series E Debentures Offering. After the partial redemption, Cdn$24.7 million principal amount of the Series D Debentures remain outstanding.

The Series E Debentures have a maturity date of January 31, 2025. The Series E Debentures bear interest at a rate of 6.00% per year, and are convertible into our common shares at an initial conversion rate of approximately 238.0952 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$4.20 per common share.

*Williams Lake Extension*

In December 2017, we entered into an extension of the Energy Purchase Agreement ("EPA") with BC Hydro for our Williams Lake project. The original EPA was scheduled to terminate on March 31, 2018. This agreement extends the term to June 30, 2019, or September 30, 2019 at the option of BC Hydro. Under the terms of the EPA extension, the revised dispatch model and pricing will result in de minimis Project Adjusted EBITDA from the time the contract becomes effective in April 2018. This extension is subject to approval of the BC Utilities Commission. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Supplementary Non-GAAP Information – *Project Adjusted EBITDA*" for a reconciliation of these figures to the directly comparable GAAP measure.

*Nipigon Enhanced Dispatch Contract*

The existing enhanced dispatch contract for Nipigon provides fixed monthly payments to that plant through October 31, 2018 during such time that the plant is not operational. After the expiration of this contract in 2018, Nipigon was expected to revert to the original PPA and operate under the PPA through December 31, 2022. In December 2017, we entered into a long-term enhanced dispatch contract with the IESO for Nipigon for the period November 1, 2018 through December 31, 2022. As a result, the PPA will be terminated effective October 31, 2018. The long-term enhanced dispatch contract provides for Nipigon to receive monthly capacity-type payments based on the original PPA, with adjustment for operational savings that will be shared with the IESO. In addition, the project will function as a market participant and earn energy revenues for those periods during which it operates. In 2018, we will accelerate amortization of the remaining $18.3 million of intangible PPA asset through October 31, 2018.

***Performance highlights***

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Project revenue | $ 431.0 | $ 399.2 | $ 420.2 |
| Project (loss) income | $ (47.4) | $ 10.1 | $ (41.4) |
| Net loss attributable to Atlantic Power Corporation | $ (98.6) | $ (122.4) | $ (62.4) |
| Loss per share attributable to Atlantic Power Corporation—basic and diluted | $ (0.86) | $ (1.02) | $ (0.51) |
| Project Adjusted EBITDA[1] | $ 288.8 | $ 202.2 | $ 208.9 |

(1) See reconciliation and definition below under Supplementary Non-GAAP Financial Information.

Revenue increased from $399.2 million in the year ended December 31, 2016 to $431.0 million in the year ended December 31, 2017, an increase of $31.8 million. The primary drivers of the increase are as follows:

- *OEFC settlement* – we recorded approximately $28.6 million of revenue at North Bay, Kapuskasing and Tunis related to our settlement agreement entered into with the OEFC in April 2017 arising out of our disagreement over the interpretation of the price escalator calculation in our PPAs at these projects;

- *Curtis Palmer* – a $13.3 million increase in revenue from higher water flows;

- *San Diego projects* – a $6.6 million increase in revenue at our San Diego projects, primarily due to higher steam revenue than 2016; and

- *Morris* – a $4.0 million increase in revenue at our Morris project, which underwent a turbine overhaul in 2016.

These increases in project revenue were partially offset by:

- *Enhanced dispatch contracts* – under the enhanced dispatch contracts with the IESO, we suspended operations at our Kapuskasing, North Bay and Nipigon projects, which resulted in approximately $19.4 million of lower revenue than 2016.

Consolidated project loss was $47.4 million for the year ended December 31, 2017, a decrease of $57.5 million from the prior year project income of $10.1 million. The primary drivers of the decrease are as follows:

- *Impairment of goodwill, long-lived assets and equity investments*– impairment increased $101.3 million from $85.9 million in 2016 to $187.2 million in 2017;

- *Change in fair value of derivative instruments* – the change in the fair value of our derivative instruments decreased $35.8 million to $2.1 million in 2017 from $37.9 million in 2016. The decrease is primarily due to the expiration of unfavorable gas purchase agreements in December 2016 accounted for as derivatives at our North Bay and Kapuskasing projects.

These decreases in project income were partially offset by increases in project income resulting from:

- *Revenue* – revenue increased $31.8 million as discussed above; and

- *Fuel expense* - fuel expense decreased from $149.5 million in 2016 to $106.4 million in 2017 primarily due to the $46.3 million impact of the expiration of fuel contracts at North Bay and Kapuskasing on December 31, 2016. These projects did not operate in 2017 under the terms of their enhanced dispatch contracts.

A detailed discussion of project income (loss) by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 60.

***Factors and trends that may influence our results***

The primary components of our financial results are (i) the financial performance of our projects, (ii) unrealized gains and losses associated with derivative instruments, (iii) interest expense and foreign exchange impacts on corporate-level debt, and (iv) impairment of goodwill, long-lived assets and equity method investments. We have recorded net losses in four of the past five years, primarily as a result of non-cash losses associated with items (ii), (iii) and (iv) above, which are described in more detail in the following paragraphs.

*Financial performance of our projects*

The operating performance of our projects supports cash distributions that are made to us after all operating, maintenance, capital expenditures and debt service requirements are satisfied at the project-level. Our projects are able to generate cash flows because they generally receive revenues from long-term contracts that provide relatively stable cash flows. Risks to the stability of these distributions include the following:

- Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between September 30, 2018 and December 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. See "Risk Factors—Risks Related to Our Business and Our Projects—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition."

- Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility and its customers, but some of our projects do have exposure to market power and fuel prices. See Item 1A. "Risk Factors—Risks Related to Our Business and Our Projects—Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our hedging arrangements.

- Our most significant exposure to market power prices exists at the Chambers and Morris projects. At Chambers, our utility customer has the right to sell a portion of the plant's output to the spot power market if it is economical to do so, and the Chambers project shares in the profits from those sales. With low demand for electricity the utility reduces its dispatch to minimum contracted levels during off-peak hours. At Morris, approximately 68% of the facility's capacity is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of that portion of the facility. See Item 1A. "Risk Factors—Risks Related to Our Business and Our Projects—Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition."

- The performance of our projects is impacted by a variety of operational and other factors, including water and waste heat levels, planned and unplanned outages and maintenance requirements, delays in start-up, sourcing of fuel from suppliers, among others. For additional details regarding the various operational and other risks that we face, see "Risk Factors—Risks Related to Our Business and Our Projects."

- When revenue or fuel contracts at our projects expire, we may not be able to sell power or procure fuel under new arrangements that provide the same level or stability of project cash flows. If re-contracted, the degree of the expected decline in cash flows from operations is subject to market conditions when we execute new PPAs for these projects and is difficult to estimate at this time. See Item 1A. "Risk Factors—Risks Related to Our Business and Our Projects—The expiration or termination of PPAs could have a material adverse impact on our business, results of operations and financial condition." These projects will be free of debt when their PPAs expire, which we expect to provide us with some flexibility to pursue the most economic type of contract without restrictions that might be imposed by project-level debt.

- Two of our projects have non-recourse project-level debt that can restrict the ability of the project to make cash distributions. The project-level debt agreements typically contain cash flow coverage ratio tests that restrict the project's cash distributions if project cash flows do not exceed project-level debt service requirements by a specified amount. Although these projects are currently meeting these debt service requirements, we cannot provide any assurances that these projects will generate enough future cash flow to meet any applicable ratio tests and be able to make distributions to us. See "Liquidity and Capital Resources—Project-level debt" and Item 1A. "Risk Factors—Risks Related to Our Structure—Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make acquisitions or investments or issue additional indebtedness we otherwise would seek to do."

*Non-cash gains and losses on derivatives instruments*

In the ordinary course of our business, we execute natural gas purchase agreements and natural gas swap contracts to manage our exposure to fluctuations in commodity prices, foreign currency forward contracts to manage our exposure to fluctuations in foreign exchange rates and interest rate swaps to manage our exposure to changes in interest rates on variable rate project-level debt. Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our derivative instruments.

*Interest expense and other costs associated with debt*

Interest expense relates to both non-recourse project-level debt and corporate-level debt. A portion of our convertible debentures and long-term corporate level debt are denominated in Canadian dollars. These debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar-denominated debt.

*Impairment*

We test our long-lived assets and goodwill for impairment at least annually, or more often if deemed appropriate based on the determination of management of the occurrence of certain trigger events under our impairment policy. We recorded \$187.1 million (\$101.1 million at consolidated projects and \$86.0 million at projects accounted for under the equity method of accounting), \$85.9 million and \$127.8 million of goodwill and long-lived asset impairments for the years ended December 31, 2017, 2016 and 2015, respectively. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all. It is possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. When the affected project temporarily or permanently ceases operations, or when we have an expectation that we will be unable to renew or renegotiate the PPA, the value of the project may be impaired such that we would record an impairment loss. See "Critical Accounting Policies – Goodwill" for a discussion of the trends and factors that have resulted in the recorded goodwill and long-lived asset impairments.

**Consolidated Overview and Results of Operations**

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as a result of significant project asset sales and in order to align our reportable business segments with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. The segment classified as Un-Allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs are not allocated to the operating segments when determining segment profit or loss. Project (loss) income is the primary GAAP measure of our operating results and is discussed below by reportable segment.

***2017 compared to 2016***

The following tables and discussion summarize our consolidated results of operations and provide an analysis by reportable segment:

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2017 | 2016 | $ change | % change |
| Project revenue: | | | | |
| Energy sales | $ 148.9 | $ 184.2 | $ (35.3) | (19.2)% |
| Energy capacity revenue | 105.8 | 141.9 | (36.1) | (25.4)% |
| Other | 176.3 | 73.1 | 103.2 | 141.2 % |
| | 431.0 | 399.2 | 31.8 | 8.0 % |
| Project expenses: | | | | |
| Fuel | 106.3 | 149.5 | (43.2) | (28.9)% |
| Operations and maintenance | 87.8 | 105.2 | (17.4) | (16.5)% |
| Depreciation and amortization | 113.1 | 113.5 | (0.4) | (0.4)% |
| | 307.2 | 368.2 | (61.0) | (16.6)% |
| Project other expense: | | | | |
| Change in fair value of derivative instruments | 2.1 | 37.9 | (35.8) | (94.5)% |
| Equity in (loss) earnings of unconsolidated affiliates | (54.8) | 35.9 | (90.7) | NM |
| Interest expense, net | (17.5) | (9.2) | (8.3) | 90.2 % |
| Impairment | (101.1) | (85.9) | (15.2) | 17.7 % |
| Other income, net | 0.1 | 0.4 | (0.3) | (75.0)% |
| | (171.2) | (20.9) | (150.3) | NM |
| Project (loss) income | (47.4) | 10.1 | (57.5) | NM |
| Administrative and other expenses: | | | | |
| Administration | 23.6 | 22.6 | 1.0 | 4.4 % |
| Interest expense, net | 64.2 | 106.0 | (41.8) | (39.4)% |
| Foreign exchange loss | 16.3 | 13.9 | 2.4 | 17.3 % |
| Other income, net | (0.4) | (3.9) | 3.5 | (89.7)% |
| | 103.7 | 138.6 | (34.9) | (25.2)% |
| Loss from operations before income taxes | (151.1) | (128.5) | (22.6) | 17.6 % |
| Income tax benefit | (58.1) | (14.6) | (43.5) | NM |
| Net loss | (93.0) | (113.9) | 20.9 | (18.3)% |
| Net income attributable to preferred shares of a subsidiary company | 5.6 | 8.5 | (2.9) | (34.1)% |
| Net loss attributable to Atlantic Power Corporation | $ (98.6) | $ (122.4) | $ 23.8 | (19.4)% |

***Project (Loss) Income by Segment***

| | Year Ended December 31, 2017 | | | | |
|---|---|---|---|---|---|
| | **East U.S.** | **West U.S.** | **Canada** | **Un-Allocated Corporate** | **Consolidated Total** |
| Project revenue: | | | | | |
| Energy sales | $ 87.3 | $ 33.0 | $ 28.6 | $ — | $ 148.9 |
| Energy capacity revenue | 49.4 | 45.6 | 10.8 | — | 105.8 |
| Other | 15.8 | 30.3 | 129.2 | 1.0 | 176.3 |
| | 152.5 | 108.9 | 168.6 | 1.0 | 431.0 |
| Project expenses: | | | | | |
| Fuel | 46.4 | 44.8 | 15.1 | — | 106.3 |
| Operations and maintenance | 34.5 | 26.0 | 27.6 | (0.3) | 87.8 |
| Depreciation and amortization | 35.2 | 25.6 | 51.9 | 0.4 | 113.1 |
| | 116.1 | 96.4 | 94.6 | 0.1 | 307.2 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 6.3 | — | (6.1) | 1.9 | 2.1 |
| Equity in loss of unconsolidated affiliates | (27.6) | (27.2) | — | — | (54.8) |
| Interest expense, net | (17.4) | — | (0.1) | — | (17.5) |
| Impairment | (14.7) | (57.3) | (29.1) | — | (101.1) |
| Other income, net | — | — | 0.1 | — | 0.1 |
| | (53.4) | (84.5) | (35.2) | 1.9 | (171.2) |
| Project (loss) income | $ (17.0) | $ (72.0) | $ 38.8 | $ 2.8 | $ (47.4) |

| | Year Ended December 31, 2016 | | | | |
|---|---|---|---|---|---|
| | **East U.S.** | **West U.S.** | **Canada** | **Un-Allocated Corporate** | **Consolidated Total** |
| Project revenue: | | | | | |
| Energy sales | $ 70.1 | $ 31.9 | $ 82.2 | $ — | $ 184.2 |
| Energy capacity revenue | 49.0 | 45.6 | 47.3 | — | 141.9 |
| Other | 15.4 | 23.8 | 33.0 | 0.9 | 73.1 |
| | 134.5 | 101.3 | 162.5 | 0.9 | 399.2 |
| Project expenses: | | | | | |
| Fuel | 45.3 | 36.9 | 67.3 | — | 149.5 |
| Operations and maintenance | 41.3 | 26.4 | 36.4 | 1.1 | 105.2 |
| Depreciation and amortization | 34.4 | 29.1 | 49.5 | 0.5 | 113.5 |
| | 121.0 | 92.4 | 153.2 | 1.6 | 368.2 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 9.2 | — | 25.5 | 3.2 | 37.9 |
| Equity in earnings of unconsolidated affiliates | 33.0 | 2.9 | — | — | 35.9 |
| Interest expense, net | (9.1) | — | — | (0.1) | (9.2) |
| Impairment | (15.4) | — | (70.5) | — | (85.9) |
| Other income, net | — | — | — | 0.4 | 0.4 |
| | 17.7 | 2.9 | (45.0) | 3.5 | (20.9) |
| Project income (loss) | $ 31.2 | $ 11.8 | $ (35.7) | $ 2.8 | $ 10.1 |

***East U.S.***

Project income for 2017 decreased $48.2 million from 2016 primarily due to:

- decreased project income of $48.1 million and $11.3 million at Chambers and Selkirk, respectively, primarily due to impairments of our equity investments of $47.1 million and $10.6 million recorded for the year ended December 31, 2017, respectively; and

- decreased project income of $7.5 million at Orlando primarily due to an $11.9 million decrease in the fair value of natural gas swaps and lower revenue from decreased dispatch, partially offset by $6.8 of lower fuel expense resulting from the settlement of favorable fuel swaps.

These decreases were partially offset by:

- increased project income of $13.8 million at Curtis Palmer due primarily to a $13.3 million increase in revenue from higher water flows than 2016; and

- increased project income of $5.0 million at Morris due primarily to $7.5 million of decreased maintenance expenses resulting from the overhaul of two gas turbines and one steam turbine during 2016 and $4.0 million higher revenues due to less maintenance outages than 2016. These increases were partially offset by $7.5 million of higher fuel expense.

***West U.S.***

Project income for 2017 decreased $83.8 million from 2016 primarily due to:

- decreased project income of $22.6 million, $21.0 million and $12.0 million at Naval Station, North Island and NTC primarily due to $22.5 million, $21.2 million and $13.5 million long-lived asset impairments recorded for the year ended December 31, 2017, respectively; and

- decreased project income of $30.1 million at Frederickson primarily due to a $28.3 million impairment of our investment in the project recorded for the year ended December 31, 2017.

***Canada***

Project income for 2017 increased $74.5 million from 2016 primarily due to:

- increased project income of $47.1 million at Mamquam due primarily to a $50.2 million goodwill impairment recorded for the year ended December 31, 2016, partially offset by a $2.8 million decrease in energy revenue due to lower water flows than 2016;

- increased project income of $26.6 million at North Bay due primarily to a $10.2 million goodwill and long-lived asset impairment recorded in the third quarter of 2016, $23.1 million of lower fuel expense in 2017 due to the expiration of an unfavorable fuel contract in December 2016, $3.7 million increase in revenue received due to the OEFC settlement and $2.3 million of lower maintenance expense. These increases were partially offset by a $13.6 million increased gain in the fair value of a fuel agreement accounted for as a derivative in 2016;

- increased project income of $24.8 million at Kapuskasing due primarily to $24.8 million of lower fuel expense in 2017 due to the expiration of an unfavorable fuel contract in December 2016, $8.9 million goodwill and long-lived asset impairment recorded in the third quarter of 2016 and $3.9 million of lower maintenance expense. These increases were partially offset by a $13.6 million gain in the fair value of a fuel agreement accounted for as a derivative in 2016; and

- increased project income of $6.1 million at Tunis due primarily to the collection of the OEFC settlement.

These increases were partially offset by:

- decreased project income of $27.0 million at Williams Lake primarily due to a $29.1 million long-lived asset impairment recorded for the year ended December 31, 2017; and

- decreased project income of $3.2 million at Nipigon due primarily to a $4.4 million decrease in the fair value of fuel agreements accounted for as derivatives.

***Un-Allocated Corporate***

Total project income for 2017 did not change materially from 2016.

***Administrative and other expenses (income)***

Administrative and other expenses (income) includes the income and expenses not attributable to our projects and are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non-cash items that impact Administrative and other expenses (income), which are subject to potentially significant fluctuations, include the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

*Administration*

Administration expense increased $1.0 million from 2016 primarily due to a $0.6 million increase in employee compensation costs, $0.6 million of higher professional services costs and $0.2 million of lower rent expense.

*Interest, net*

Interest expense decreased $41.8 million from 2016 primarily due to $37.6 million of deferred financing cost write-offs resulting from the extinguishment of the Senior Secured Term Loan Facilities and the repurchase and cancellation of the Series A, B, and, in part, C convertible debentures during 2016 as well as lower outstanding debt balances and a lower interest rate on the senior secured credit facilities for the year ended December 31, 2017.

*Foreign exchange loss*

Foreign exchange loss increased $2.4 million from 2016 primarily due to a $1.4 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars and $1.0 million of realized transaction losses. The U.S. dollar to Canadian dollar exchange rate was 1.25 and 1.34 at December 31, 2017 and 2016, respectively, a decrease of 6.6%. The average U.S. dollar to Canadian dollar exchange rate was 1.28 for the year ended December 31, 2017 and was 1.32 for the year ended December 31, 2016.

*Other income, net*

Other income, net decreased $3.5 million from the 2016 comparable period primarily due to a $3.7 million gain recorded on the purchase and cancellation of convertible debentures during 2016.

*Income tax benefit*

Income tax benefit for the year ended December 31, 2017 was $58.1 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $39.3 million. On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law making significant changes to the Internal Revenue Code. Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017, new limitations on the deduction of net business interest expense, and a new base erosion and anti-abuse tax. After preliminary estimates based on guidance available as of the date of this filing, the interest expense limitation and base erosion and anti-abuse tax is not expected to have a material impact to cash taxes in future tax years. The primary item impacting the tax rate for the twelve months ended December 31, 2017 is the amount related to the remeasurement of deferred tax assets and liabilities, based on the rates at which they are expected to reverse in the future for $28.5 million. In addition, the rate was further impacted by $9.9 million related to goodwill impairment. These items were offset by $34.6 million related to a net decrease to our valuation allowances, consisting primarily of decreases of $34.1 million in the United States due to the remeasurement of deferred tax assets and a decrease of $0.5 million in Canada related to income. In addition, the rate was further impacted by $20.1 million relating to operating in higher tax rate jurisdictions, $2.4 million relating to foreign exchange and $0.1 million relating to other permanent differences.

***2016 compared to 2015***

The following tables and discussion summarize our consolidated results of operations and provides an analysis by reportable segment:

| | Year ended December 31, | | | |
|---|---|---|---|---|
| | 2016 | 2015 | $ change | % change |
| Project revenue: | | | | |
| Energy sales | $ 184.2 | $ 191.5 | $ (7.3) | (3.8)% |
| Energy capacity revenue | 141.9 | 149.3 | (7.4) | (5.0)% |
| Other | 73.1 | 79.4 | (6.3) | (7.9)% |
| | 399.2 | 420.2 | (21.0) | (5.0)% |
| Project expenses: | | | | |
| Fuel | 149.5 | 165.1 | (15.6) | (9.4)% |
| Operations and maintenance | 105.2 | 103.5 | 1.7 | 1.6 % |
| Development | — | 1.1 | (1.1) | NM |
| Depreciation and amortization | 113.5 | 110.0 | 3.5 | 3.2 % |
| | 368.2 | 379.7 | (11.5) | (3.0)% |
| Project other expense: | | | | |
| Change in fair value of derivative instruments | 37.9 | 15.4 | 22.5 | 146.1 % |
| Equity in earnings of unconsolidated affiliates | 35.9 | 36.7 | (0.8) | (2.2)% |
| Interest expense, net | (9.2) | (8.2) | (1.0) | 12.2 % |
| Impairment | (85.9) | (127.8) | 41.9 | (32.8)% |
| Other income, net | 0.4 | 2.0 | (1.6) | (80.0)% |
| | (20.9) | (81.9) | 61.0 | (74.5)% |
| Project income (loss) | 10.1 | (41.4) | 51.5 | NM |
| Administrative and other expenses (income): | | | | |
| Administration | 22.6 | 29.4 | (6.8) | (23.1)% |
| Interest expense, net | 106.0 | 107.1 | (1.1) | (1.0)% |
| Foreign exchange loss (gain) | 13.9 | (60.3) | 74.2 | NM |
| Other income, net | (3.9) | (3.1) | (0.8) | 25.8 % |
| | 138.6 | 73.1 | 65.5 | 89.6 % |
| Loss from continuing operations before income taxes | (128.5) | (114.5) | (14.0) | 12.2 % |
| Income tax benefit | (14.6) | (30.4) | 15.8 | (52.0)% |
| Loss from continuing operations | (113.9) | (84.1) | (29.8) | 35.4 % |
| Income from discontinued operations, net of tax | — | 19.5 | (19.5) | NM |
| Net loss | (113.9) | (64.6) | (49.3) | 76.3 % |
| Net loss attributable to noncontrolling interests | — | (11.0) | 11.0 | (100.0)% |
| Net income attributable to Preferred share dividends of a subsidiary company | 8.5 | 8.8 | (0.3) | NM |
| Net loss attributable to Atlantic Power Corporation | $ (122.4) | $ (62.4) | $ (60.0) | 96.2 % |

***Project Income (Loss) by Segment***

| | Year Ended December 31, 2016 | | | | |
|---|---|---|---|---|---|
| | East U.S. | West U.S. | Canada | Un-Allocated Corporate | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 70.1 | $ 31.9 | $ 82.2 | $ — | $ 184.2 |
| Energy capacity revenue | 49.0 | 45.6 | 47.3 | — | 141.9 |
| Other | 15.4 | 23.8 | 33.0 | 0.9 | 73.1 |
| | 134.5 | 101.3 | 162.5 | 0.9 | 399.2 |
| Project expenses: | | | | | |
| Fuel | 45.3 | 36.9 | 67.3 | — | 149.5 |
| Operations and maintenance | 41.3 | 26.4 | 36.4 | 1.1 | 105.2 |
| Depreciation and amortization | 34.4 | 29.1 | 49.5 | 0.5 | 113.5 |
| | 121.0 | 92.4 | 153.2 | 1.6 | 368.2 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 9.2 | — | 25.5 | 3.2 | 37.9 |
| Equity in earnings of unconsolidated affiliates | 33.0 | 2.9 | — | — | 35.9 |
| Interest expense, net | (9.1) | — | — | (0.1) | (9.2) |
| Impairment | (15.4) | — | (70.5) | — | (85.9) |
| Other income, net | — | — | — | 0.4 | 0.4 |
| | 17.7 | 2.9 | (45.0) | 3.5 | (20.9) |
| Project income (loss) | $ 31.2 | $ 11.8 | $ (35.7) | $ 2.8 | $ 10.1 |

| | Year Ended December 31, 2015 | | | | |
|---|---|---|---|---|---|
| | East U.S. | West U.S. | Canada | Un-Allocated Corporate | Consolidated Total[(1)] |
| Project revenue: | | | | | |
| Energy sales | $ 77.0 | $ 36.3 | $ 78.2 | $ — | $ 191.5 |
| Energy capacity revenue | 54.9 | 45.4 | 49.0 | — | 149.3 |
| Other | 18.1 | 22.9 | 37.5 | 0.9 | 79.4 |
| | 150.0 | 104.6 | 164.7 | 0.9 | 420.2 |
| Project expenses: | | | | | |
| Fuel | 58.5 | 39.0 | 67.6 | — | 165.1 |
| Operations and maintenance | 31.8 | 32.0 | 37.4 | 2.3 | 103.5 |
| Development | — | — | — | 1.1 | 1.1 |
| Depreciation and amortization | 32.7 | 29.1 | 47.3 | 0.9 | 110.0 |
| | 123.0 | 100.1 | 152.3 | 4.3 | 379.7 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | — | — | 16.0 | (0.6) | 15.4 |
| Equity in earnings of unconsolidated affiliates | 33.7 | 3.1 | — | (0.1) | 36.7 |
| Interest expense, net | (8.2) | — | — | — | (8.2) |
| Impairment | (13.7) | — | (114.1) | — | (127.8) |
| Other (expense) income, net | (0.1) | — | — | 2.1 | 2.0 |
| | 11.7 | 3.1 | (98.1) | 1.4 | (81.9) |
| Project income (loss) | $ 38.7 | $ 7.6 | $ (85.7) | $ (2.0) | $ (41.4) |

(1) Excludes the Wind Projects, which were sold in June 2015 and classified as discontinued operations.

***East U.S.***

Project income for 2016 decreased $7.5 million from 2015 primarily due to:

- decreased project income of $5.1 million at Curtis Palmer due primarily to a $1.7 million increase in goodwill impairment and a $3.1 million decrease in revenue from lower water flows than 2015; and

- decreased project income of $12.8 million at Morris due primarily to $7.4 million of increased maintenance expenses resulting from the overhaul of two gas turbines and one steam turbine during 2016. The maintenance outage also resulted in $9.1 million lower revenues and $6.8 million of lower fuel expense.

These increases were partially offset by:

- increased project income of $9.4 million at Orlando due primarily to a $7.4 million increase in the fair value of natural gas swaps and higher revenue from increased dispatch and a $1.8 million decrease in fuel expense due to lower gas prices.

***West U.S.***

Project income for 2016 increased $4.2 million from 2015 primarily due to:

- increased project income of $7.1 million at Manchief due primarily to $8.0 million of lower maintenance expense related to a 2015 maintenance overhaul.

This increase was partially offset by:

- decreased project income of $2.3 million at Oxnard, which underwent a planned maintenance outage in the fourth quarter of 2016.

***Canada***

Project loss for 2016 decreased $50.0 million from 2015 primarily due to:

- increased project income from Williams Lake of $119.2 million due primarily to a $109.7 million goodwill and long-lived asset impairment recorded in 2015 and $9.3 million of lower depreciation expense during 2016 related to the prior-year long-lived asset impairment;

- increased project income from Calstock of $2.5 million due primarily to a $4.4 million goodwill impairment recorded in 2015 and $0.9 million lower fuel costs. This was partially offset by a $2.8 million decrease in revenue due to the expiration of a rate adder under its PPA and lower waste heat; and

- increased project income from Nipigon of $1.8 million due primarily to a $1.7 million increase in the fair value of fuel agreements accounted for as derivatives.

These increases were partially offset by:

- increased project loss from Mamquam of $43.6 million due primarily to a $50.2 million goodwill impairment recorded in the third quarter of 2016, partially offset by a $4.6 million increase in energy revenue due to higher water flows than 2015 and a $2.1 million decrease in operation and maintenance expense due to a maintenance outage in 2015;

- increased project loss from North Bay of $13.8 million due primarily to a $10.2 million goodwill and long-lived asset impairment recorded in the third quarter of 2016 and $5.9 million increased amortization related to the acceleration of a PPA intangible resulting from the termination of the PPA in December 2016. This was partially offset by a $3.9 million increase in the fair value of a fuel agreement accounted for as a derivative; and

- increased project loss from Kapuskasing of $13.4 million due primarily to an $8.9 million goodwill and long-lived asset impairment recorded in the third quarter of 2016 and $5.9 million increased amortization related to the acceleration of a PPA intangible resulting from the termination of the PPA in December 2016. This was partially offset by a $3.9 million increase in the fair value of a fuel agreement accounted for as a derivative.

***Un-Allocated Corporate***

Total project income increased $4.8 million from 2015 primarily due to a $3.8 million increase in the fair value of interest rate swap agreements, a $1.3 million decrease in employee compensation and a $1.1 million decrease in development costs, partially offset by a $2.3 million gain on the sale of our Frontier solar development project recorded in 2015.

***Administrative and other expenses (income)***

Administrative and other expenses (income) include the income and expenses not attributable to our projects and are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non-cash items that impact Administrative and other expenses (income), which are subject to potentially significant fluctuations, include the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

*Administration*

Administration expense decreased $6.8 million or 23.1% from 2015 primarily due to a $3.6 million decrease in employee compensation costs, $1.8 million of lower professional services costs and $1.5 million of lower rent expense.

*Interest, net*

Interest expense decreased $1.1 million or 1.0% from the comparable 2015 period primarily due to:

- decreased convertible debenture interest expense of $6.5 million resulting from the repurchase and cancellation of the Series A, B and, in part, C and D convertible debentures during 2016; and

- decreased deferred financing costs amortization of $3.9 million resulting from the extinguishment of the Senior Secured Term Loan Facilities and the repurchase and cancellation of the Series A, B, and, in part, C convertible debentures during 2016.

These decreases were partially offset by:

- increased interest expense on our corporate debt of $8.9 million due to higher interest rates and principal balance on our New Term Loan Facility, partially offset by lower interest expense from the redemption of our 9.0% Notes in 2015.

*Foreign exchange loss (gain)*

Foreign exchange loss was $13.9 million for the year ended December 31, 2016, a change of $74.2 million from the $60.3 million gain recorded in 2015 period primarily due to a $33.4 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The repurchase of Cdn$152.1 million Canadian dollar-denominated convertible debentures was the most significant factor in the decrease. The U.S. dollar to Canadian dollar exchange rate was 1.34 and 1.38 at December 31, 2016 and 2015, respectively, a decrease of 3.0%. The average U.S. dollar to Canadian dollar exchange rate was 1.32 for the year ended December 31, 2016 and was 1.27 for the year ended December 31, 2015.

*Other income, net*

Other income, net increased $0.8 million from the 2015 comparable period primarily due to a $3.9 million gain recorded on the purchase and cancellation of convertible debentures during 2016, as compared to a $3.1 million gain on the purchase and cancellation of convertible debentures recorded during 2015.

*Income tax benefit*

Income tax benefit for the year ended December 31, 2016 was $14.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $33.4 million. The primary items impacting the tax rate for the year ended December 31, 2016 were $22.3 million related to goodwill impairment, $6.9 million related to foreign exchange and $1.3 million related to return to provision adjustments. In addition, the rate was further impacted by a net increase to our valuation allowances of $10.8 million, consisting primarily of increases of $27.2 million in Canada related to losses and a decrease of $16.4 million in the United States due to tax restructurings and additional earnings. These items were offset by $18.0 million Canadian capital losses recognized on tax restructurings, $2.9 million related to operating in higher tax rate jurisdictions and $1.5 million related to changes in tax rates.

**Project Operating Performance**

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in GWhs. Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve substantially all of their respective capacity payments. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in thousands of Net GWh.

***Generation***

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in Net GWh)** | **2017** | **2016** | **2015 (1)** | **% change 2017 vs. 2016** | **% change 2016 vs. 2015** |
| **Segment** | | | | | |
| East U.S. | 2,478.5 | 2,430.2 | 2,628.0 | 2.0 % | (7.5)% |
| West U.S. | 1,601.5 | 1,506.6 | 1,835.9 | 6.3 % | (17.9)% |
| Canada | 934.7 | 1,977.2 | 1,889.4 | (52.7)% | 4.6 % |
| Total | 5,014.7 | 5,914.0 | 6,353.3 | (15.2)% | (6.9)% |

(1) Excludes the Wind Projects, which were sold in June 2015 and are classified as discontinued operations.

*Year ended December 31, 2017 compared with Year ended December 31, 2016*

Aggregate power generation for 2017 decreased 15.2% from 2015 primarily due to:

- decreased generation in the Canada segment primarily due to a decrease of 928.6 net GWh on a combined basis at Kapuskasing, Nipigon and North Bay, due to their suspended operation status under the enhanced dispatch contracts.

This decrease was partially offset by:

- increased generation in the East U.S. segment primarily due to a 107.6 net GWh increase in generation at

Curtis Palmer due to higher water flows than the comparable period in 2016 and a 68.8 net GWh increase in generation at Morris due to a maintenance outage in 2016. These increases were partially offset by an 83.9 net GWh decrease in generation at Selkirk due to lower dispatch from low merchant power prices; and

- increased generation in the West U.S. segment primarily due to a 47.1 net GWh increase in generation at Frederickson, and a 34.6 net GWh increase in generation at Manchief due to higher dispatch than 2016.

*Year ended December 31, 2016 compared with Year ended December 31, 2015*

Aggregate power generation for 2016 decreased 6.9% from 2015 primarily due to:

- decreased generation in the West U.S. segment, primarily due to a 206.9 net GWh decrease in generation at Frederickson, which had decreased dispatch from lower demand, and a 110.1 net GWh decrease in generation at Manchief due to lower dispatch; and

- decreased generation in the East U.S. segment, primarily due to an 83.4 net GWh decrease in generation at Morris due to a maintenance outage in the third quarter of 2016, an 83.3 net GWh decrease at Selkirk due to lower dispatch from low merchant power prices and a 53.5 net GWh decrease at Chambers due to a maintenance outage in the second quarter of 2016.

This decrease was partially offset by:

- increased generation in the Canada segment, primarily due to a 133.3 net GWh increase in generation at Mamquam due to higher water flows during 2016. Mamquam also underwent a maintenance outage during 2015.

***Availability***

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 [(1)] | % change 2017 vs. 2016 | % change 2016 vs. 2015 |
| **Segment** | | | | | |
| East U.S. | 88.8 % | 93.1 % | 96.9 % | (4.6)% | (3.9)% |
| West U.S. | 92.1 % | 92.1 % | 92.8 % | — % | (0.8)% |
| Canada | 92.8 % | 95.3 % | 93.9 % | (2.6)% | 1.5 % |
| Weighted average | 90.3 % | 93.3 % | 95.2 % | (3.2)% | (2.0)% |

(1) Excludes the Wind Projects, which were sold in June 2015 and are classified as discontinued operations.

*Year ended December 31, 2017 compared with Year ended December 31, 2016*

Weighted average availability for 2017 decreased to 90.3% from 93.3% in 2016 primarily due to:

- decreased availability in the East U.S. segment resulting from decreased availability at Kenilworth, which underwent a turbine overhaul in 2017, and decreased availability at Orlando due to a forced maintenance outage in 2017. These decreases were partially offset by increased availability at Morris, which underwent a planned maintenance outage in the third quarter of 2016;

- decreased availability in the West U.S. segment primarily due to a planned maintenance outage at Frederickson, offset by increased availability at NTC, which underwent an outage in 2016; and

- decreased availability in the Canada segment resulting from Williams Lake, primarily due to forced maintenance outages.

*Year ended December 31, 2016 compared with Year ended December 31, 2015*

Weighted average availability for 2016 decreased to 93.3% from 95.2% in 2015 primarily due to:

- decreased availability in the East U.S. segment resulting from decreased availability at Morris, which underwent a planned maintenance outage in the third quarter of 2016; and

- decreased availability in the West U.S. segment resulting from decreased availability at Frederickson, which underwent a maintenance outage in 2016, offset by increased availability at Manchief, which underwent a maintenance outage in 2015.

These decreases were partially offset by:

- increased availability in the Canada segment resulting from increased availability at Mamquam, which underwent a maintenance outage in the 2015 period.

## Supplementary Non-GAAP Financial Information

### *Project Adjusted EBITDA*

The key measurement we use to evaluate the results of our business is Project Adjusted EBITDA. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. 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. We believe that Project Adjusted EBITDA is a useful measure of financial results at our projects because it excludes non-cash impairment charges, gains or losses on the sale of assets and non-cash mark-to-market adjustments, all of which can affect year-to-year comparisons. Project Adjusted EBITDA is before corporate overhead expense. The most directly comparable GAAP measure to Project Adjusted EBITDA is Project (loss) income. A reconciliation of Net (loss) income to Project (loss) income and to Project Adjusted EBITDA is provided under “Project Adjusted EBITDA” below. Project Adjusted EBITDA for our equity investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below.

| | Year ended December 31, | | | $ change | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 [1] | 2017 | 2016 |
| **Net loss** | $ (93.0) | $ (113.9) | $ (64.6) | $ 20.9 | $ (49.3) |
| Net income from discontinued operations, net of tax | — | — | 19.5 | — | (19.5) |
| Income tax benefit | (58.1) | (14.6) | (30.4) | (43.5) | 15.8 |
| Loss from operations before income taxes | (151.1) | (128.5) | (114.5) | (22.6) | (14.0) |
| Administration | 23.6 | 22.6 | 29.4 | 1.0 | (6.8) |
| Interest expense, net | 64.2 | 106.0 | 107.1 | (41.8) | (1.1) |
| Foreign exchange loss (gain) | 16.3 | 13.9 | (60.3) | 2.4 | 74.2 |
| Other income, net | (0.4) | (3.9) | (3.1) | 3.5 | (0.8) |
| **Project (loss) income** | $ (47.4) | $ 10.1 | $ (41.4) | $ (57.5) | $ 51.5 |
| **Reconciliation to Project Adjusted EBITDA** | | | | | |
| Depreciation and amortization | 133.2 | 133.5 | 130.1 | (0.3) | 3.4 |
| Interest expense, net | 19.2 | 10.9 | 9.8 | 8.3 | 1.1 |
| Change in the fair value of derivative instruments | (2.1) | (37.9) | (15.4) | 35.8 | (22.5) |
| Impairment | 187.1 | 85.9 | 127.8 | 101.2 | (41.9) |
| Other income, net | (1.2) | (0.3) | (2.0) | (0.9) | 1.7 |
| **Project Adjusted EBITDA** | $ 288.8 | $ 202.2 | $ 208.9 | $ 86.6 | $ (6.7) |
| **Project Adjusted EBITDA by segment** | | | | | |
| East U.S. | 112.5 | 92.4 | 104.8 | 20.1 | (12.4) |
| West U.S. | 49.1 | 51.2 | 46.9 | (2.1) | 4.3 |
| Canada | 125.8 | 58.8 | 59.7 | 67.0 | (0.9) |
| Un-Allocated Corporate | 1.4 | (0.2) | (2.5) | 1.6 | 2.3 |
| **Total** | $ 288.8 | $ 202.2 | $ 208.9 | $ 86.6 | $ (6.7) |

(1) Excludes the Wind Projects, which were sold in June 2015 and are classified as discontinued operations.

*East U.S.*

The following table summarizes Project Adjusted EBITDA for our East U.S. segment for the periods indicated:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | % change 2017 vs. 2016 | % change 2016 vs. 2015 |
| **East U.S.** | | | | | |
| Project Adjusted EBITDA | $ 112.5 | $ 92.4 | $ 104.8 | 22 % | (12)% |

*Year ended December 31, 2017 compared with Year ended December 31, 2016*

Project Adjusted EBITDA for 2017 increased $20.1 million or 22% from 2016 primarily due to increases in Project Adjusted EBITDA of:

- $12.6 million at Curtis Palmer due to $13.3 million of increased revenues from higher water flows than 2016;
- $4.6 million at Orlando primarily due to lower fuel expense resulting from the settlements of favorable fuel swaps; and
- $4.0 million at Morris due to $7.5 million of decreased maintenance expenses and $4.0 million of higher revenues resulting from the overhaul of two gas turbines and one steam turbine during 2016. These increases were partially offset by $7.5 million higher fuel expense.

*Year ended December 31, 2016 compared with Year ended December 31, 2015*

Project Adjusted EBITDA for 2016 decreased $12.4 million or 22% from 2015 primarily due to decreases in Project Adjusted EBITDA of:

- $10.1 million at Morris due to $7.9 million of increased maintenance expenses resulting from the overhaul of two gas turbines and one steam turbine during 2016. The maintenance outage also resulted in $9.1 million lower revenues and $6.8 million of lower fuel expense; and

- $3.3 million at Curtis Palmer due to $3.1 million of decreased revenues from lower water flows than the 2015 period.

These decreases were partially offset by an increase in Project Adjusted EBITDA of:

- $2.1 million at Orlando primarily due to $1.8 million of lower fuel expense from lower natural gas prices than 2015.

*West U.S.*

The following table summarizes Project Adjusted EBITDA for our West U.S. segment for the periods indicated:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | % change 2017 vs 2016 | % change 2016 vs 2015 |
| **West U.S.** | | | | | |
| Project Adjusted EBITDA | $ 49.1 | $ 51.2 | $ 46.9 | (4)% | 9 % |

*Year ended December 31, 2017 compared with Year ended December 31, 2016*

Project Adjusted EBITDA for 2017 decreased by $2.1 million or 4% from 2016 primarily due to a decrease in Project Adjusted EBITDA of:

- $2.1 million at Frederickson primarily due to higher maintenance expense than 2016, partially offset by higher revenue.

*Year ended December 31, 2016 compared with Year ended December 31, 2015*

Project Adjusted EBITDA for 2016 increased by $4.3 million or 9% from 2015 primarily due to an increase in Project Adjusted EBITDA of:

- $7.2 million at Manchief attributable to $8.0 million of lower maintenance expense in 2016. Manchief underwent a maintenance overhaul during 2015.

This increase was partially offset by a decrease in Project Adjusted EBITDA of:

- $2.2 million at Oxnard, which underwent a planned maintenance outage in the fourth quarter of 2016.

*Canada*

The following table summarizes Project Adjusted EBITDA for our Canada segment for the periods indicated:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | % change 2017 vs. 2016 | % change 2016 vs. 2015 |
| **Canada** | | | | | |
| Project Adjusted EBITDA | $ 125.8 | $ 58.8 | $ 59.7 | 114 % | (2)% |

*Year ended December 31, 2017 compared with Year ended December 31, 2016*

Project Adjusted EBITDA for 2017 increased by $67.0 million from 2016 primarily due to increases in Project Adjusted EBITDA of:

- $60.6 million at Kapuskasing and North Bay primarily due to $21.8 million received from the OEFC settlement. These projects were not operational under the terms of their enhanced dispatch contracts during 2017. Additionally, each project had unfavorable fuel contracts that expired in 2016. As a result of these factors, gross margin increased $32.5 million and maintenance expense decreased $6.2 million in 2017;

- $6.0 million at Tunis primarily due to the collection of the OEFC settlement; and

- $2.8 million at Nipigon primarily due to $7.0 million of lower fuel expense due to non-operational status under the terms of its enhanced dispatch contract, partially offset by a $4.4 million decrease in the fair value of fuel swap agreements.

These increases were partially offset by a decrease in Project Adjusted EBITDA of:

- $3.2 million at Mamquam, due to lower water flows than 2016 and forced outages in 2017.

*Year ended December 31, 2016 compared with Year ended December 31, 2015*

Project Adjusted EBITDA for 2016 decreased by $0.9 million from 2015 primarily due to decreases in Project Adjusted EBITDA of:

- $2.9 million at Kapuskasing primarily due to $1.1 million of lower waste heat revenue, $1.1 million of fuel costs under a fuel contract and $0.8 million of increased operations and maintenance expense for turbine repairs;

- $2.2 million at Calstock due primarily to a $2.8 million decrease in revenue due to the expiration of a rate adder under its PPA and lower waste heat; and

- $2.0 million at North Bay due to $1.3 million of lower waste heat revenue and $1.1 million of fuel costs under a fuel contract.

These decreases were partially offset by an increase in Project Adjusted EBITDA of:

- $6.7 million at Mamquam, due to $4.6 million of increased energy revenue from higher water flows in 2016 and a $2.1 million decrease in operations and maintenance expense resulting from a maintenance outage in 2015.

*Un-allocated Corporate*

The following table summarizes Project Adjusted EBITDA for our Un-allocated Corporate segment for the periods indicated:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | % change 2017 vs. 2016 | % change 2016 vs. 2015 |
| **Un-allocated Corporate** | | | | | |
| Project Adjusted EBITDA | $ 1.4 | $ (0.2) | $ (2.5) | NM | 92 % |

*Year ended December 31, 2017 compared with Year ended December 31, 2016*

Project Adjusted EBITDA increased by $1.6 million from 2016 primarily due to lower administrative expenses related to the reductions in workforce.

*Year ended December 31, 2016 compared with Year ended December 31, 2015*

Project Adjusted EBITDA for 2016 increased by $2.3 million or 92% from the comparable 2015 period primarily due to increased development costs and decreased administrative expense due to a reduction in workforce.

***Consolidated Cash Flow***

***2017 compared to 2016***

The following table reflects the changes in cash flows for the periods indicated:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | Change |
| Net cash provided by operating activities | $ 169.2 | $ 112.3 | $ 56.9 |
| Net cash provided by (used in) investing activities | 2.8 | (0.5) | 3.3 |
| Net cash used in financing activities | (178.9) | (98.6) | (80.3) |

*Operating Activities*

Cash flow from our projects may vary from year to year based on working capital requirements and the operating performance of the projects, as well as changes in prices under PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re-contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

For the year ended December 31, 2017, the net increase in cash flows provided by operating activities of $56.9 million was primarily the result of the following:

- *OEFC Settlement* – we received approximately $26.6 million related to our settlement with the OEFC for the year December 31, 2017;
- *Impact of lower fuel costs and enhanced dispatch contracts in Ontario* – we recorded $33.9 million of higher gross margin at North Bay, Kapuskasing and Nipigon as a result of the expiration of unfavorable gas purchase agreements in December 2016, as well as operating under the enhanced dispatch contracts in 2017;
- *Operations and maintenance* – we incurred $17.4 million of lower operations and maintenance costs, as a result of decreased maintenance expense at Morris and Williams Lake, which underwent outages in 2016, and at North Bay and Kapuskasing, which did not operate during 2017 due to the terms of

their enhanced dispatch contracts; and

- *Hydrological conditions at Curtis Palmer* – higher water flows at our Curtis Palmer project had a $13.3 million impact on cash flows from operations.

These increases were partially offset by a decrease in net cash provided by operating activities that was primarily the result of the following:

- *Working capital* – changes in working capital resulted in a $24.3 million decrease in cash flows from operating activities as compared to 2016 primarily due to $10.5 million of timing in revenue receipts at our Kapuskasing, Nipigon and North Bay and $3.4 million decrease in prepaids, supplies and other assets;

- *Hydrological conditions and maintenance outage at Mamquam* – lower water flows and a forced outage at our Mamquam project had a $3.2 million impact on cash flows from operations; and

- *Waste heat* – lower waste heat at our Calstock project had a $2.6 million impact on cash flows from operations.

*Investing Activities*

For the year ended December 31, 2017, the net increase in cash flows used in investing activities of $3.3 million was primarily the result of the following:

- *Restricted cash* – the change in restricted cash increased $7.1 million from 2016, primarily due to lower restricted cash requirements from decreased outstanding debt balances;

- *Purchases of PP&E* – investments in capitalized plant additions were $1.9 million lower than 2016; and

- *Proceeds from sale of equity investment* – we received $1.0 million from the sale of our 17.7% equity interest in Selkirk Cogen L.P.

These increases were partially offset by the following:

- *Reimbursement of construction costs* – we received a reimbursement of $4.8 million in capitalized costs from the customer for a construction project at Morris in 2016.

*Financing Activities*

For the year ended December 31, 2017, the net decrease in cash flows from financing activities of $80.3 million was primarily the result of the following:

- *The Credit Facilities* – we received $231.1 million of net proceeds from issuance of the senior secured term loan in 2016 after repayment of the previous term loan;

- *Corporate and project-level debt repayments* – we made $69.4 million of higher principal payments than 2016 primarily due to the $54.6 million retirement of Piedmont's non-recourse project-level debt, as well as higher principal payments on our Term Loan; and

- *Preferred share repurchases* – we paid $3.1 million in 2017 to repurchase and cancel preferred shares.

These decreases were partially offset by the following:

- *Convertible debenture repayments* – we paid $188.5 million to redeem and cancel convertible debentures in 2016;

- *Deferred financing costs* – we incurred $16.2 million of deferred financing costs related to the refinancing of the senior secured credit facilities in 2016; and

- *Common share repurchases* – we paid $0.2 million in 2017 to repurchase and cancel common shares as compared to $19.5 million in 2016.

***2016 compared to 2015***

The following table reflects the changes in cash flows for the periods indicated:

| | Year ended December 31, 2016 | Year ended December 31, 2015 | Change |
|---|---|---|---|
| Net cash provided by operating activities | $ 112.3 | $ 88.3 | $ 24.0 |
| Net cash (used in) provided by investing activities | (0.5) | 320.9 | (321.4) |
| Net cash used in financing activities | (98.6) | (446.7) | 348.1 |

*Operating Activities*

Cash flow from our projects may vary from year to year based on working capital requirements and the operating performance of the projects, as well as changes in prices under PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re-contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

For the year ended December 31, 2016, the net increase in cash flows provided by operating activities of $24.0 million was primarily the result of the following:

- *Decrease in interest payments* – we made $29.3 million in lower interest payments than 2015 primarily due to the redemption of the 9.0% Notes in July 2015 and the repurchase and cancellation of, in full, our Series A and B and, in part, our Series C convertible debentures during 2016.

This increase was partially offset by a decrease in net cash provided by operating activities primarily the result of the following:

- *Sale of the Wind Projects* – in 2015 the Wind Projects, which were sold in June 2015, provided $21.9 million of operating cash flows.

*Investing Activities*

For the year ended December 31, 2016, the net decrease in cash flows used in investing activities of 321.4 million was primarily the result of the following:

- *Sale of Wind Projects* – we received $326.3 in cash million from the sale of the Wind Projects and the Frontier solar development project in the second quarter of 2015.

This decrease was partially offset by the following:

- *Reimbursement of construction costs* – we received a reimbursement of $4.8 million in capitalized costs from the customer for a construction project at Morris.

*Financing Activities*

For the year ended December 31, 2016, the net decrease in cash flows used in financing activities of $348.1 million was primarily the result of the following:

- *The New Credit Facilities* – we received $679.0 million of net proceeds from the issuance of New Credit Facilities in 2016; and

- *Dividend paid to common shareholders and noncontrolling interest* – we paid $14.8 million in dividends to our common shareholders and noncontrolling interests in 2015 as compared to no such payments in 2016

These decreases were partially offset by the following:

- *Corporate and project-level debt* – we redeemed the Senior Secured Credit Facilities in full for $447.9 million in the second quarter of 2016 as compared to the $319.9 million paid to redeem our 9.0% High Yield Notes in 2015;

- *Repayment of convertible debentures* – we paid $188.5 million in cash to redeem and cancel $191.5 million aggregate principal of our Series A, B and, in part, C convertible debentures during 2016. This was a $169.6 million increase in convertible debenture repurchases from 2015; and

- *Deferred financing costs* – we incurred $16.2 million of deferred financing costs associated with the New Term Loan Facilities during 2016.

**Liquidity and Capital Resources**

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| Cash and cash equivalents | $ 78.7 | $ 85.6 |
| Restricted cash | 6.2 | 13.3 |
| Total | 84.9 | 98.9 |
| Revolving credit facility availability | 119.5 | 118.5 |
| Total liquidity | $ 204.4 | $ 217.4 |

Our primary source of liquidity is distributions from our projects and availability under our Revolving Credit Facility. Our liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from September 30, 2018 to December 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash. See "Risk Factors—Risks Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing external growth opportunities or fund our operations."

We expect to reinvest approximately $36.2 million in our portfolio in the form of project capital expenditures and maintenance expenses in 2018. Such investments are generally paid at the project level. See "—Capital and Maintenance Expenditures." We do not expect any other material or unusual requirements for cash outflow in 2018 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months from February 27, 2018.

***Repurchases of Securities***

On December 8, 2017, our Board of Directors approved an NCIB for each series of our convertible unsecured subordinated debentures. Under the NCIBs, our broker may purchase up to 10% of the public float of our convertible debentures and common shares and up to 5% of the amount issued and outstanding of APPEL's preferred shares, determined as of December 15, 2017, up to the following limits:

| | Maturity Date | Interest Rates | Limit on Purchase (Principal Amount) Total Limit |
|---|---|---|---|
| Convertible Debenture | June 2019 | 5.75 % | $ 4,253,200 |
| Convertible Debenture | December 2019 | 6.00 % | Cdn$ 8,097,800 |

| | Limit on Purchase (Number of Shares) Total Limit [(1)] |
|---|---|
| Common Shares | 11,308,946 |
| Series 1 Preferred Shares | 237,500 |
| Series 2 Preferred Shares | 116,904 |
| Series 3 Preferred Shares | 83,095 |

(1) Represented 10% of the public float for the Common Shares and 5% of the amount issued and outstanding for the Preferred Shares.

The NCIBs commenced on December 29, 2017 and will expire on December 28, 2018 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIBs. In certain circumstances, we may be required to suspend the NCIBs under applicable law.

The Board authorization permits the Company to repurchase common and preferred shares and convertible debentures. Therefore, in addition to the current NCIBs, from time to time we may repurchase our securities, including our common shares, our convertible debentures and our APPEL preferred shares through open market purchases, including pursuant to one or more "Rule 10b5-1 plans" pursuant to such provision under the United States Securities Exchange Act of 1934, as amended, NCIBs, issuer self tender or substantial issuer bids, or in privately negotiated transactions. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions, other market opportunities and other factors. Any share repurchases outside of previously authorized NCIBs would be effected after taking into account our then current cash position and then anticipated cash obligations or business opportunities.

### *Corporate Debt Service Obligations*

The following table summarizes the maturities of our corporate debt at December 31, 2017:

| | Maturity Date | Interest Rates | Remaining Principal Repayments | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|---|---|---|
| Senior secured term loan facility[(1)] | April 2023 | 4.60% - 4.90% | $ 540.0 | $ 90.0 | $ 65.0 | $ 105.0 | $ 80.0 | $ 75.0 | $ 125.0 |
| Atlantic Power Income LP Note | June 2036 | 5.95% | 167.4 | — | — | — | — | — | 167.4 |
| Convertible Debenture [(2)] | June 2019 | 5.75% | 42.5 | — | 42.5 | — | — | — | — |
| Convertible Debenture [(2)] | December 2019 | 6.00% | 64.5 | — | 64.5 | — | — | — | — |
| Total Corporate Debt | | | $ 814.4 | $ 90.0 | $ 172.0 | $ 105.0 | $ 80.0 | $ 75.0 | $ 292.4 |

(1) The Credit Facility contains a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of APLP Holdings Limited Partnership ("APLP Holdings") and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the Credit Facilities and the 5.95% Medium Term Notes due June 23, 2036 ("MTNs"), letters of credit costs to meet the requirements of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Note that failing to meet the mandatory amortization requirements is not an event of default, but could result in APLP Holdings being unable to make distributions to Atlantic Power Corporation and Atlantic Power Preferred Equity Limited being unable to pay dividends to its shareholders. The amortization profile in the table above is based on principal payments according to the targeted principal amount described in (ii) above.

(2) The Series C Debentures maturing in June 2019 will be redeemed, in full, on March 5, 2018 and the Series D Debentures maturing in December 2019 will be redeemed, in part, on March 7, 2018 with proceeds from the Series E Debenture Offering. See *Recent Events* for the discussion of the Series E Debentures Offering.

### *Credit Facilities*

On April 13, 2016, APLP Holdings Limited Partnership ("APLP Holdings"), our wholly-owned subsidiary, entered into new Senior Secured Credit Facilities, comprising $700 million in aggregate principal amount of Senior Secured Term Loan facilities (the "Term Loans") and $200 million in aggregate principal amount of senior secured credit facilities (the "Revolver" and together with the Term Loans, the "Credit Facilities"). At December 31, 2017, $540.0 million of the Term Loans is outstanding and letters of credit in an aggregate face amount of $80.5 million are issued (but not drawn) pursuant to the revolving commitments under the Revolver and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service, and (ii) to support contractual credit support obligations of APLP Holdings and its subsidiaries and of certain other affiliates of the Company.

Borrowings under Credit Facilities are available in U.S. dollars and Canadian dollars and, at inception, bore interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate as applicable, plus an applicable margin between 4.00% and 5.00% that varied depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. In April 2017, the repricing of the Credit Facilities became effective reducing the interest rate margin on the term loan and revolver by 0.75% to LIBOR plus 4.25%. In October 2017, a second repricing reduced the interest rate margin on the Credit Facilities by another 0.75% to LIBOR plus 3.50%. We also extended the maturity date of the Revolver by one year through April 2022. The Term Loans mature in April 2023.

The Term Loans include a 3% original issue discount. Letters of credit are available to be issued under the Revolver until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. In addition to paying interest on outstanding principal under the Credit Facilities, APLP Holdings is required to pay a commitment fee of 0.75% times the unused commitments under the Revolver.

The Credit Facilities are secured by a pledge of the equity interests in APLP Holdings and certain of its subsidiaries, guaranties from certain of the subsidiaries of APLP Holdings (the "Subsidiary Guarantors"), a downstream guarantee from the Company, a limited recourse guaranty from Atlantic Power GP II, Inc., the entity that holds all of the equity interest in APLP Holdings, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of APLP Holdings and its subsidiaries (subject to certain exceptions), and certain other assets. The Credit Facilities also have the benefit of a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The reserve requirement is maintained utilizing a letter of credit. APLP, a wholly-owned, indirect subsidiary of the Company, is a party to an existing indenture governing its Cdn$210 million aggregate principal amount MTNs that prohibits APLP (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, APLP Holdings has granted an equal and ratable security interest in the collateral package securing the New Credit Facilities in favor of the trustee under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The negative covenants include a requirement that APLP Holdings and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 at December 2017 to 4.25:1.00 from June 30, 2020, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 3.00:1.00 at December 31, 2017 to 4.00:1.00 from June 30, 2022. In addition, the Credit Agreement includes customary restrictions and limitations on APLP Holdings' and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to certain exceptions and other customary carve-outs and various thresholds. Specifically, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the new term loan that declines quarterly based on a predetermined specified schedule.

Under the Credit Agreement, if a Change of Control (as defined in the Credit Agreement) occurs, unless APLP Holdings elects to make a voluntary prepayment of the term loans under the Credit Facilities, it will be required to offer each electing lender a prepayment of such lender's term loans under the Credit Facilities at a price equal to 101% of par. In addition, in the event that APLP Holdings elects to repay, prepay, refinance or replace all or any portion of the term loan facilities within six months from the repricing date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid, refinanced or replaced.

The Credit Agreement also contains a mandatory amortization feature and other mandatory prepayment provisions, including prepayments:

- from the proceeds of asset sales (except from the sale proceeds of certain excluded projects), insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and

- with respect to excess cash flows, to be determined by using the greater of (i) 50% of the cash flow of APLP Holdings and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the Credit Facilities and the MTNs, funding of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Failure to achieve the specified target principal amount for any quarter does not constitute a default by APLP Holdings.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of APLP Holdings and its subsidiaries, bankruptcy, material judgments rendered against APLP Holdings or certain of its subsidiaries, certain ERISA or regulatory events, a Change of Control of APLP Holdings (solely with respect to the Revolver), or defaults under certain guaranties and collateral documents securing the Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

***Project-Level Debt Service Obligations***

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at December 31, 2017. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. See Note 11, *Long-term debt.* Although all of our projects with non-recourse loans are currently meeting their debt service requirements, we cannot provide any assurances that our projects will generate enough future cash flow to meet any applicable ratio tests in order to be able to make distributions to us.

*Non-Recourse Debt*

The range of interest rates presented represents the rates in effect at December 31, 2017. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

| | Maturity Date | Range of Interest Rates | Total Remaining Principal Repayments | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|---|---|---|
| **Consolidated Projects:** | | | | | | | | | |
| Epsilon Power Partners | January 2019 | 4.45 % | $ 7.2 | $ 6.5 | $ 0.7 | $ — | $ — | $ — | $ — |
| Cadillac | August 2025 | 6.18 % | 24.0 | 3.0 | 3.1 | 3.1 | 2.7 | 3.3 | 8.8 |
| Total Consolidated Projects | | | 31.2 | 9.5 | 3.8 | 3.1 | 2.7 | 3.3 | 8.8 |
| **Equity Method Projects:** | | | | | | | | | |
| Chambers[(1)] | December 2019 and 2023 | 4.50 % - 5.00 % | 42.9 | — | 5.2 | 7.8 | 8.8 | 10.1 | 11.0 |
| Total Equity Method Projects | | | 42.9 | — | 5.2 | 7.8 | 8.8 | 10.1 | 11.0 |
| Total Project-Level Debt | | | $ 74.1 | $ 9.5 | $ 9.0 | $ 10.9 | $ 11.5 | $ 13.4 | $ 19.8 |

(1) In June 2014, Chambers refinanced its project debt and issued (i) Series A (tax exempt) Bonds due December 2023, of which our proportionate share is $41.3 million, and (ii) Series B (taxable) Bonds due December 2019, of which our proportionate share is $1.6 million. The above table does not include our $4.2 million proportionate share of issuance premiums.

***Preferred shares issued by a subsidiary company***

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares") priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. Beginning on June 30, 2012, the Series 1 Shares were redeemable by the subsidiary company at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares") priced at Cdn$25.00 per share. The Series 2

Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate was reset on December 31, 2014 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares were and will be redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares had and will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%. On December 31, 2014, 1,661,906 of Series 2 shares were converted to Series 3 shares.

The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of the subsidiary company. If, and for so long as, the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

The subsidiary company paid aggregate dividends of $8.7 million and $8.5 million on Series 1 Shares, Series 2 Shares and Series 3 Shares for the years ended December 31, 2017 and 2016, respectively.

***Capital and Maintenance Expenditures***

Capital expenditures and maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. On-going capital expenditures for assets of this nature are generally not significant because most major expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately $36.2 million in 2018 in our portfolio in the form of project capital expenditures and maintenance expenses. As explained above, these investments are generally paid at the project level. We believe one of the benefits of our diverse fleet is that plant overhauls and other major expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations provide a source of data to assess maintenance needs. In addition, we utilize predictive and risk-based analysis to refine our expectations, prioritize our spending and balance the funding requirements necessary for these expenditures over time. Future capital expenditures and maintenance expenses may exceed the projected 2018 level as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

We invested approximately $38.2 million of project capital expenditures and maintenance expenses for the year ended December 31, 2017. In all cases, scheduled maintenance outages during the year ended December 31, 2017 occurred at such times that did not adversely impact the facilities' availability requirements under their respective PPAs.

***Restricted Cash***

At December 31, 2017, restricted cash totaled $6.2 million as compared to $13.3 million as of December 31, 2016.

**Contractual Obligations and Commercial Commitments**

The following table summarizes our contractual obligations as of December 31, 2017:

| | Payment Due by Period | | | | |
|---|---|---|---|---|---|
| | Less than 1 year | 1-3 Years | 3-5 Years | Thereafter | Total |
| Long-term debt including estimated interest[(1)(2)] | $ 144.5 | $ 351.2 | $ 206.8 | $ 441.4 | $ 1,143.9 |
| Operating leases | 0.5 | 0.2 | — | — | 0.7 |
| Operations and maintenance commitments | 0.4 | 0.8 | 0.8 | — | 2.0 |
| Fuel purchase and transportation obligations | 3.9 | 25.1 | 34.4 | 22.9 | 86.3 |
| Other liabilities | 0.4 | 0.4 | — | — | 0.8 |
| Total contractual obligations | $ 149.7 | $ 377.7 | $ 242.0 | $ 464.3 | $ 1,233.7 |

(1) Debt represents our proportionate share of project long-term debt and corporate-level debt. Project debt is non-recourse to us and is generally amortized during the term of the respective revenue generating contracts of the projects. The range of interest rates on long-term consolidated project debt at December 31, 2017 was 4.45% to 6.18%.

(2) The Series C Debentures maturing in June 2019 will be redeemed, in full, on March 8, 2018 and the Series D Debentures maturing in December 2019 will be redeemed, in part, on March 7, 2018 with proceeds from the Series E Debentures Offering. See *Recent Events* for the discussion of the Series E Debentures Offering.

**Guarantees**

We and our subsidiaries entered into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint venture agreements, operation and maintenance agreements, fuel purchase and transportation agreements and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for certain tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

**Off-Balance Sheet Arrangements**

As of December 31, 2017, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

**Critical Accounting Policies and Estimates**

Accounting standards require information be included in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining the useful lives and recoverability of property, plant and equipment and PPAs, the recoverability of equity investments, the recoverability of goodwill, the recoverability of deferred tax assets, the fair value of our derivatives instruments, and fair values of acquired assets.

For a summary of our significant accounting policies, see Note 2 to the consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others; these policies are discussed below.

***Long-lived asset impairment and other-than-temporary decline in value***

Long-lived assets

Long-lived assets, such as property, plant and equipment, and other intangible assets subject to depreciation and amortization, are reviewed for impairment annually or whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Examples of such indicators include, among other factors, a significant decrease in the market price of a long-lived asset, adverse business climate, current period loss combined with a history of losses or the projection of future losses, and a change in our intent to hold or a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life. We also review a project for impairment at the earlier of executing a new PPA (or other arrangement) or six months prior to the expiration of an existing PPA. Factors such as the business climate, including current energy and market conditions, environmental regulation, the condition of assets, and the ability to secure new PPAs are considered when evaluating long-lived assets for impairment.

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of the asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value. Our asset groups have been determined to be at the plant level, which is the lowest level in which independent, separately identifiable cash flows have been identified.

We determine the fair value of our reporting units using an income approach with discounted cash flow ("DCF") models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected merchant power prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our goodwill impairment tests for our reporting units are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilize estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows of the particular reporting unit and is based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources. We utilized the assistance of valuation experts to perform quantitative impairment tests for several of our reporting units. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

The valuation of long-lived assets, equity method investments and goodwill is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities. Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of a goodwill impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our reporting units may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long-term forecasts. See "Risk Factors—Risks Related to Our Business and Our Projects—Impairment of goodwill or long-lived assets could have a material adverse effect on our business, results of operations and financial condition".

We recorded long-lived asset impairments of $29.1 million, $22.5 million, $21.2 million and $13.5 million, respectively at our Williams Lake, Naval Station, North Island and Naval Training Center reporting units in the year ended December 31, 2017. We recorded long-lived asset impairments of $3.8 million and $2.1 million, respectively, at our North Bay and Kapuskasing reporting units in the year ended December 31, 2016. See Item 15 — Note 8, *Goodwill and long-lived asset impairment* for discussion of these impairments.

Equity method investments

Investments in and the operating results of 50%-or-less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. The standard for determining whether an impairment must be recorded is whether a decline in the value is considered an other-than-temporary decline in value. The evaluation and measurement of impairments for our equity method investments involves the same uncertainties as described for long-lived assets. Similarly, these estimates are subjective, and the impact of variations in these estimates could be material. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment or, where applicable, estimated sales proceeds that are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

We recorded investment impairments of $47.1 million, $28.3 million and $10.1 million, respectively, at our Chambers, Frederickson and Selkirk projects in the year ended December 31, 2017. See Item 15 — Note 5, *Equity method investments in unconsolidated affiliates* for discussion of these impairments.

***Goodwill***

Goodwill is not amortized. Instead, it is reviewed for impairment annually (in the fourth quarter) or more frequently if indicators of impairment exist. A significant amount of judgment is involved in determining if an indicator of impairment has occurred. Such indicators may include a prolonged decline in our market capitalization, deterioration in general economic conditions, adverse changes in the market in which a reporting unit operates, decreases in energy or capacity revenues as the result of re-contracting or increases in input costs that have a negative effect on earnings and cash flows, or a trend of negative or declining cash flows over multiple periods, among others. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill. Our goodwill is allocated among and evaluated for impairment at the reporting unit level, which is one level below our operating segments.

We apply a standard that provides an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. These factors include an assessment of macroeconomic and industry conditions, market events and circumstances as well as the overall financial performance of our reporting units. Because we have not been able to make a more likely than not determination of whether the fair value of a reporting unit is less than the carrying value for our reporting units, we performed quantitative tests for the years ended December 31, 2017 and 2016.

Under the quantitative impairment test, the evaluation of impairment involves comparing the current fair value of each reporting unit to its carrying value, including goodwill. In January 2017, the FASB issued authoritative guidance, which removed the requirement to perform a hypothetical purchase price allocation to measure goodwill impairment. Under this guidance, goodwill impairment is measured as the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. We early adopted this guidance for our annual goodwill impairment test conducted at November 30, 2017.

We recorded a goodwill impairment of $14.7 million at our Curtis Palmer reporting unit in the year ended

December 31, 2017. We recorded goodwill impairments of $50.2 million, $15.4 million, $6.7 million, $6.5 million and $1.2 million, respectively, at our Mamquam, Curtis Palmer, Kapuskasing, North Bay and Moresby Lake reporting units in the year ended December 31, 2016. See Item 15 — Note 8, *Goodwill and long-lived asset impairment* for discussion of these impairments.

***Fair value of derivatives***

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices and foreign currency rates and to balance our exposure to variable interest rates. We believe that these derivatives are generally effective in realizing these objectives. We also enter into long-term fuel purchase agreements accounted for as derivatives that do not meet the scope exclusion for normal purchase or normal sales.

In determining fair value for our derivative assets and liabilities, we generally use the market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk and/or the risks inherent in the inputs to the valuation techniques.

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Our derivative instruments are classified as Level 2. The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified with market data and valuation techniques do not involve significant judgment. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk-free interest rate. We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties.

Certain derivative instruments qualify for a scope exception to fair value accounting, as they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

**Recent Accounting Developments**

See Item 15 — Note 2, *Summary of Significant Accounting Policies,* to the consolidated financial statements for a discussion of recent accounting developments.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and commodity prices, will affect our cash flows or the value of our holdings of financial instruments. The objective of market risk management is to minimize the impact that market risks have on our cash flows as described in the following paragraphs.

Our market risk-sensitive instruments and positions have been determined to be “other than trading.” Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel and electricity commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions. See Note 14, *Accounting for derivative instruments and hedging activities* for additional information.

**Fuel Commodity Market Risk**

Our current and future cash flows are impacted by changes in electricity, natural gas, biomass and coal prices. See "Item 1A. Risk Factors—Risks Related to Our Business and Our Projects—Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects." We often employ (i) tolling structures, whereby an offtaker is responsible for fuel procurement, (ii) long-term fuel contracts, where we lock in a set quantity of fuel at a predetermined price or (iii) pass-through arrangements, whereby the cost of fuel is borne by the ultimate offtaker. The combination of long-term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by passing through changes in fuel prices to the buyer of the energy.

*Natural Gas*

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

Our 50%-owned Orlando project is exposed to changes in natural gas prices. We have entered into various natural gas swaps to effectively fix the price of 9.9 million MMBtu of future natural gas purchases at Orlando, which includes approximately 90%, 100% and 50% of our 2018, 2019 and 2020 gas consumption, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2017. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations. A $1.00 MMBtu change in the price of natural gas would have an estimated a $0.4 million impact to cash distributions for 2018.

*Biomass*

Biomass suppliers are generally small companies and unwilling or unable to enter into long-term contracts at a fixed price, volume or term. At some plants, a significant portion of the cost of biomass fuel consists of the price of diesel fuel used in forestry operations and over the road transportation of the fuel to the projects. A decline in major industries such as pulp, paper and lumber can have a negative effect on the available biomass supply. Reduction in volumes from the forestry sector can also impact availability and price.

Our Cadillac project does not have a long-term biomass fuel contract. A $2 per Ton change from our budgeted wood waste cost at Cadillac would have an estimated $0.5 million total impact on forecasted cash distributions in 2018 based on planned operations.

Our Piedmont project does not have a long-term biomass fuel contract. A $2 per Ton change from our budgeted wood waste cost at Piedmont would have an estimated $1.2 million total impact on forecasted cash distributions in 2018 based on planned operations.

Our Calstock project has six fuel suppliers, three of which provide up to 65% of its fuel requirements and are under contract to provide fuel, with a tipping fee until 2019. We are exposed to the remaining 35% of the project's estimate fuel requirements. A $1 per Ton change from our budgeted wood waste costs at Calstock would have an estimated $0.2 million impact on forecasted cash distributions in 2018 based on planned operations.

*Coal*

Our 40%-owned Chambers project is exposed to changes in coal prices. For 2018, we forecasted an average coal price of $98 per Ton. A 10% change from our forecasted price would impact cash distributions from Chambers by an estimated $1.8 million for 2018 based on planned operations.

A significant portion of energy revenue at Orlando is indexed to the price of coal. We estimate that a $0.25 per

MMBtu price change in this index would have a $1.0 million impact on cash distributions from Orlando for 2018.

**Electricity Commodity Market Risk**

Our current and future cash flows are impacted by changes in electricity prices when our projects operate with no PPA or at projects that operate with PPAs that are based on spot market pricing. Our most significant exposure to market power prices is at the Chambers and Morris projects.

At our 40%-owned Chambers project, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is profitable to do so, and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the utility takes less generation, which negatively affects the project's operating margin. In 2018, projected cash distributions from Chambers would change by approximately $0.1 million per 10% change in the PJM-East spot price of electricity.

At Morris, where we own 100% of the project, the facility can sell approximately 120 MW above the offtaker's demand into the grid at market prices. If market prices do not justify the increased generation the project has no requirement to sell power in excess of the offtaker's demand, which can negatively impact operating margins. In 2018, projected cash distributions from Morris would change by approximately $0.7 million per 10% change in the spot price of electricity based on the forecasted level of approximately 200,000 MWh of grid sales and all other variables being held constant.

When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced and in some cases, significantly. Our project may not be able to secure a new agreement and could be exposed to sell power at spot market price. See Item 1A. "Risk Factors—Risk Related to Our Business and Our Projects—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition." It is possible that subsequent PPAs or the spot market may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations.

**Foreign Currency Exchange Risk**

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates as we generate cash flow in U.S. dollars and Canadian dollars. We currently have Canadian dollar payment obligations for preferred dividends, interest on our Canadian dollar-denominated convertible debentures and our Medium Term Notes. Principal and interest payments for our senior secured term loans as well as our U.S. dollar-denominated convertible debenture are made in U.S. dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the future interest and principal payments, preferred dividends and other working capital requirements.

We expected Canadian dollar cash flows to exceed our Canadian dollar obligations in 2017, primarily due to revenues received from the OEFC settlement. In July 2017, we entered into foreign exchange forward contracts to sell a total of Cdn$10 million at an exchange rate of 1.2481 in Cdn$3.3 million tranches on each of March 2018, June 2018 and December 2018. In July 2017, we also entered into foreign exchange forward contracts to sell a total of Cdn$10 million at an exchange rate of 1.2943 in tranches of Cdn$5.0 million in March 2018, Cdn$3.0 million in June 2018 and Cdn$2.0 million in December 2018. In September 2017, we entered into foreign exchange forward contracts to sell Cdn$5.0 million at an exchange rate of 1.2196 in September 2018.

The following table contains the components of recorded foreign exchange (gain) loss for the years ended December 31, 2017, 2016, and 2015:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Unrealized foreign exchange (gain) loss: | | | |
| Convertible debentures, corporate debt, and other | $ 15.1 | $ 13.8 | $ (60.5) |
| Foreign currency forwards | 0.1 | — | — |
| | 15.2 | 13.8 | (60.5) |
| Realized foreign exchange loss | 1.1 | 0.1 | 0.2 |
| | $ 16.3 | $ 13.9 | $ (60.3) |

A 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar would have a $21.1 million impact on the carrying value of our corporate debt and convertible debentures denominated in Canadian dollars at December 31, 2017.

**Interest Rate Risk**

Changes in interest rates impact cash payments that are required on our debt instruments as approximately 18% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at variable rates or is not financially hedged through the use of interest rate swaps. After considering the impact of interest rate swaps described below, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest expense at equity investments, by approximately $1.6 million at December 31, 2017.

*The Partnership*

APLP Holdings has entered into several interest rate swap agreements to mitigate its exposure to changes in the Adjusted Eurodollar Rate for $354.2 million notional amount of the remaining $540 million aggregate principal amount of borrowings under the Term Loans. These interest rate swap agreements expire at various dates through March 31, 2020. Borrowings under the Term Loans bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.50%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 4.5% all-in rate on the Term Loan Facility. The weighted average rate of these swap agreements is 1.10%, resulting in an all-in rate of approximately 4.60% for $354.2 million of the Term Loans. In January 2018, APLP Holdings entered into additional interest rate swap agreements. For the period beginning June 30, 2018 through September 30, 2019, we mitigated exposure to changes in interest rates for $100 million notional amount at a one-month LIBOR fixed rate of 2.18% and for the period beginning October 1, 2019 through December 31, 2020, for $200 million notional amount at a one-month LIBOR fixed rate of 2.42%.

*Cadillac*

We have an interest rate swap at our consolidated Cadillac project to economically fix its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt and changes in its fair market value are recorded in other comprehensive loss ("OCL"). The interest rate swap expires on September 30, 2025.

In accounting for the cash flow hedge, gains and losses on the derivative contract are reported in OCL, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net loss. That is, for a cash flow hedge, all effective components of the derivative contract's gains and losses are recorded in OCL, pending occurrence of the expected transaction. OCL consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net loss. Thus, in highly effective cash flow hedges, where there is no ineffectiveness, OCL changes by exactly as much as the derivative contracts and there is no impact on net loss until the expected transaction occurs.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our consolidated financial statements are appended to the end of this Annual Report on Form 10-K, beginning on page F-1.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated the company's disclosure controls and procedures, as defined in Rules 13a- 15(e) and 15d-15(e) of the Exchange Act, as of the end of the period covered by this report, and have concluded that these controls and procedures were effective.

Our management, including our Chief Executive Officer and our Chief Financial Officer, concluded that the consolidated financial statements in this Annual Report on Form 10-K fairly present, in all material respects, the Company's financial condition, results of operations and cash flows for the periods presented, in conformity with GAAP.

(b) Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-14(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017 using the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on our evaluation under the COSO framework, management has concluded that our internal control over financial reporting is effective as of December 31, 2017 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the controls may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.

The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 15 of this annual report Form 10-K on page F-2.

(c) Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth fiscal quarter ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION

On February 27, 2018, the Company, Atlantic Power Services, LLC and Joseph Cofelice, the Company's Executive Vice President — Commercial Development, entered into an amendment (the "Amendment") to Mr. Cofelice's existing employment agreement, by and among the same parties and dated as of September 15, 2015 (the "Original Employment Agreement").

The Amendment amends the Original Employment Agreement to provide that, in the event Mr. Cofelice's employment is terminated by the Company without Cause (as defined in the Original Employment Agreement) or by Mr. Cofelice for Good Reason (as defined in the Original Employment Agreement), in each case within the twelve-month period following a Change in Control (as defined in the Amendment), Mr. Cofelice will be entitled to receive his accrued salary through the date of termination as well as a termination payment equal to the sum of a prorated amount of his target annual bonus for the year in which his termination occurs and two times his base salary. Upon such a termination, Mr. Cofelice will also receive continued medical insurance for 18 months following his termination.

Mr. Cofelice's entitlement to these termination benefits, other than accrued salary, are conditioned upon his execution of a general release of claims against the Company in the form attached to the Original Employment Agreement.

Other than the amendments described above to Mr. Cofelice's termination benefits upon certain terminations within the twelve month period following a Change in Control, the Original Employment Agreement remains in full force and effect, including with respect to Mr. Cofelice's termination benefits upon a termination not within the twelve-month period following a Change in Control.

This description of the Amendment does not purport to be complete and is qualified in its entirety by reference to the Amendment (a copy of which is filed as Exhibit 10.41 to this Annual Report on Form 10-K) and the Original Employment Agreement (a copy of which was filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 16, 2015), and is incorporated herein by reference.

Because this report is being filed within four business days from the date of the reportable event, we have made the foregoing disclosure in this report instead of in a Form 8-K under Item 5.02 (Compensatory Arrangements of Certain Officers).

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information concerning our directors and executive officers required by Item 10 will be included in the Proxy Statement and is incorporated herein by reference.

We have adopted a code of ethics that applies to directors, managers, officers and employees. This code of ethics, titled "Code of Business Conduct and Ethics," is posted on our website. The internet address for our website is *www.atlanticpower.com*, and the "Code of Business Conduct and Ethics" may be found from our main Web page by clicking first on "About Us" and then on "Code of Conduct."

We intend to satisfy any disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the "Code of Business Conduct and Ethics" by posting such information on our website, on the Web page found by clicking through to "Conduct of Conduct" as specified above.

## ITEM 11. EXECUTIVE COMPENSATION

The information concerning our directors and executive officers required by Item 11 will be included in the Proxy Statement and is incorporated herein by reference.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information concerning security ownership and other matters required by Item 12 will be included in the Proxy Statement and is incorporated herein by reference.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information concerning certain relationships and related transactions required by Item 13 will be included in the Proxy Statement and is incorporated herein by reference.

## ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information concerning principal accountant fees and services required by Item 14 will be included in the Proxy Statement and is incorporated herein by reference.

## PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

See "Index to Consolidated Financial Statements" on page F-1 of this Annual Report on Form 10-K.

(a)(2) Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page F-1 of this Annual Report on Form 10-K. Schedules other than that listed have been omitted because of the absence of the conditions under which they are required or because the information required is shown in the consolidated financial statements or the notes thereto.

(a)(3) Exhibits

## EXHIBIT INDEX

| Exhibit No. | Description |
|---|---|
| 2.1 | Plan of Arrangement of Atlantic Power Corporation, dated as of November 24, 2005 |
| 2.2 | Arrangement Agreement, dated as of June 20, 2011, among Capital Power Income L.P., CPI Income Services Ltd., CPI Investments Inc. and Atlantic Power Corporation |
| 3.1 | Articles of Continuance of Atlantic Power Corporation, dated as of June 29, 2010 |
| 4.1 | Form of common share certificate |
| 4.2 | Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada |
| 4.3 | First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada |
| 4.4 | Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada |
| 4.5 | Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada |
| 4.6 | Second Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated July 5, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada |
| 4.7 | Third Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated August 17, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada |
| 4.8 | Fourth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of November 29, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A. |
| 4.9 | Fifth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 11, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A. |
| 4.10 | Sixth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of March 22, 2013, among Atlantic Power Corporation and Computershare Trust Company of Canada |

| Exhibit No. | Description |
|---|---|
| 4.11 | Seventh Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of January 29, 2018, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A. |
| 4.12 | Indenture, dated as of November 4, 2011, by and among Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association |
| 4.13 | First Supplemental Indenture, dated as of November 5, 2011, by and among the New Guarantors signatory thereto, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association |
| 4.14 | Second Supplemental Indenture, dated as of November 5, 2011, by and among Curtis Palmer LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association |
| 4.15 | Third Supplemental Indenture, dated as of February 22, 2012, by and among Atlantic Oklahoma Wind, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association |
| 4.16 | Fourth Supplemental Indenture, dated as of August 3, 2012, by and among Atlantic Rockland Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association |
| 4.17 | Fifth Supplemental Indenture, dated as of November 29, 2012, by and among Atlantic Ridgeline Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association |
| 4.18 | Sixth Supplemental Indenture, dated as of January 29, 2013, by and among the New Guarantors named therein, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association |
| 4.19 | Registration Rights Agreement, dated as of November 4, 2011, by and among, Atlantic Power Corporation, the Guarantors listed on Schedule A thereto and Morgan Stanley & Co. LLC and TD Securities (USA) LLC, as representatives of the several Initial Purchasers |
| 4.20 | Shareholder Rights Plan Agreement, dated effective as of February 28, 2013, between Atlantic Power Corporation and Computershare Investor Services, Inc., which includes the Form of Right Certificate as Exhibit A |
| 4.21 | Advance Notice Policy, dated April 1, 2013 |
| 10.1 | Credit and Guaranty Agreement, dated as of February 24, 2014, among Atlantic Power Limited Partnership, as Borrower, Certain Subsidiaries of Atlantic Power Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of American, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Joint Lead Arrangers and Joint Bookrunners, Union Bank, N.A. and RBC Capital Markets, as Revolver Joint Lead Arrangers and Revolver Joint Bookrunners, Union Bank, N.A. and Royal Bank of Canada, as Revolver Co- Documentation Agents, and Goldman Sachs Lending Partners LLC, as Administrative Agent and Collateral Agent |
| 10.2 | Second Amended and Restated Credit Agreement dated August 2, 2013, as amended, among Atlantic Power Corporation, Atlantic Power Generation, Inc. and Atlantic Power Transmission, Inc., the Lenders signatory thereto and Bank of Montreal, as Administrative Agent |
| 10.3 | Consent, dated as of November 19, 2012, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc. the Lenders signatory thereto and Bank of Montreal, as Administrative Agent |
| 10.4 | Consent and Release, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., the Subsidiaries signatory thereto, the Lenders signatory thereto and Bank of Montreal, as Administrative Agent and Collateral Agent |

| Exhibit No. | Description |
|---|---|
| 10.5 | Modification and Joinder Agreement, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Ridgeline Energy LLC, PAH RAH Holding Company LLC, Ridgeline Eastern Energy LLC, Ridgeline Energy Solar LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Energy Holdings, Inc., Ridgeline Alternative Energy LLC, Frontier Solar LLC, PAH RAH Project Company LLC, Monticello Hills Wind LLC, Dry Lots Wind LLC, Smokey Avenue Wind LLC, Saunders Bros. Transportation Corporation, Bruce Hill Wind LLC, South Mountain Wind LLC, Great Basin Solar Ranch LLC, Goshen Wind Holdings LLC, Meadow Creek Holdings LLC, Ridgeline Holdings Junior Inc., Rockland Wind Ridgeline Holdings LLC, Meadow Creek Intermediate Holdings LLC and the other Subsidiaries party thereto in favor of Bank of Montreal, as Administrative Agent |
| 10.6+ | Employment Agreement, dated April 15, 2013, between Atlantic Power Corporation and Terrence Ronan |
| 10.7+ | Addendum to Executive Employment Agreements of each of Terrence Ronan and Edward Hall, dated August 30, 2013 |
| 10.8+ | Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation |
| 10.9+ | Third Amended and Restated Long-Term Incentive Plan |
| 10.10+ | Fourth Amended and Restated Long-Term Incentive Plan |
| 10.11+ | Fifth Amended and Restated Long-Term Incentive Plan |
| 10.12+ | Amendment No. 1 to the Fifth Amended and Restated Long-Term Incentive Plan of the Company |
| 10.13 | Termination of the Operating Agreement of Canadian Hills Wind, LLC, dated as of December 28, 2012 |
| 10.14 | Purchase and sale agreement, dated as of January 30, 2013 among Quantum Lake LP, LLC, Quantum Lake GP, LLC, Quantum Pasco LP, LLC, Quantum Pasco GP, LLC, Quantum Auburndale LP, LLC and Quantum Auburndale GP, LLC (as Buyers) and Lake Investment, LP, NCP Lake Power, LLC, Teton New Lake, LLC, NCP Dadee Power, LLC, Dade Investment, LP, Auburndale, LLC and Auburndale GP, LLC (as Sellers) |
| 10.15 | Agreement dated November 24, 2014, by and among Clinton Group and the Company |
| 10.16+ | Employment Agreement among the Company, Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015 |
| 10.17+ | Transition Equity Grant Participation Agreement between Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015 |
| 10.18 | Membership Interest Purchase Agreement by and between Atlantic Power Transmission, Inc. and Terraform AP Acquisition Holdings, LLC dated as of March 31, 2015 |
| 10.19 | Guaranty Agreement by Atlantic Power Corporation in favor of Terraform AP Acquisition Holdings, LLC, dated as of March 31, 2015 |
| 10.20 | Agreement dated May 21, 2015, by and among Mangrove Partners and the Company |
| 10.21 | Amendment No.1 to Membership Interest Purchase Agreement, dated June 3, 2015 |
| 10.22+ | Employment Agreement among the Company, Atlantic Power Services, LLC and Joseph E. Cofelice, dated September 15, 2015 |
| 10.23 | Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners |
| 10.24 | Securities Pledge Agreement, dated as of April 13, 2016, among Atlantic Power Corporation, Atlantic Power GP II, Inc. and Goldman Sachs Lending Partners LLC as Collateral Agent |

| Exhibit No. | Description |
|---|---|
| 10.25 | Amendment dated April 17, 2017 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners |
| 10.26 | Second Amendment dated October 18, 2017 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners |
| 10.27* | Amendment to Employment Agreement, by and among Atlantic Power Services, LLC, the Company and Joseph Cofelice, dated as of February 27, 2018 |
| 10.28 | Amendment No. 2 to the Fifth Amended and Restated Long-Term Incentive Plan of the Company |
| 16.1 | Letter from KPMG LLP, Chartered Accountants, to the Securities and Exchange Commission, dated August 10, 2010 |
| 21.1* | Subsidiaries of Atlantic Power Corporation |
| 23.1* | Consent of KPMG LLP |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) under the Exchange Act |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) under the Exchange Act |
| 32.1** | Certification of the Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certification of the Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101* | The following materials from our Annual Report on Form 10-K for the year ended December 31, 2017 formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows, and (v) related notes to these financial statements |

+ Indicates management contract or compensatory plan or arrangement.

* Filed herewith.

** Furnished herewith.

(b) Exhibits:

See Item 15(a)(3) above.

(c) Financial Statement Schedules:

See Item 15(a)(2) above.

## ITEM 16. FORM 10-K SUMMARY.

None.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 1, 2018

Atlantic Power Corporation
By: /s/ TERRENCE RONAN

Name: Terrence Ronan
Title: *Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ JAMES J. MOORE, JR.<br>James J. Moore, Jr. | President, Chief Executive Officer and Director<br>(principal executive officer) | March 1, 2018 |
| /s/ TERRENCE RONAN<br>Terrence Ronan | Chief Financial Officer (Duly Authorized<br>Officer and Principal Financial and Accounting Officer) | March 1, 2018 |
| /s/ IRVING R. GERSTEIN<br>Irving R. Gerstein | Chairman of the Board | March 1, 2018 |
| /s/ R. FOSTER DUNCAN<br>R. Foster Duncan | Director | March 1, 2018 |
| /s/ KEVIN T. HOWELL<br>Kevin T. Howell | Director | March 1, 2018 |
| /s/ HOLLI LADHANI<br>Holli Ladhani | Director | March 1, 2018 |
| /s/ GILBERT S. PALTER<br>Gilbert S. Palter | Director | March 1, 2018 |

## Atlantic Power Corporation

## Index to Consolidated Financial Statements

## Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Atlantic Power Corporation:

*Opinion on the Consolidated Financial Statements*

We have audited the accompanying consolidated balance sheets of Atlantic Power Corporation and subsidiaries (the Company) as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive loss, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement schedules I to II (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States)(PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 1, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

*Basis for Opinion*

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2010.

New York, New York

March 1, 2018

**Report of Independent Registered Public Accounting Firm**

To the Shareholders and Board of Directors
Atlantic Power Corporation:

*Opinion on Internal Control over Financial Reporting*

We have audited Atlantic Power Corporation and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive loss, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement schedules I to II (collectively, the consolidated financial statements) and our report dated March 1, 2018 expressed an unqualified opinion on those consolidated financial statements.

*Basis for Opinion*

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

*Definitions and Limitations of Internal Control over Financial Reporting*

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

New York, New York

March 1, 2018

## ATLANTIC POWER CORPORATION

## CONSOLIDATED BALANCE SHEETS

## (in millions of U.S. dollars)

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 78.7 | $ 85.6 |
| Restricted cash | 6.2 | 13.3 |
| Accounts receivable | 52.7 | 37.3 |
| Current portion of derivative instruments asset (Notes 13 and 14) | 2.7 | 4.0 |
| Inventory (Note 6) | 17.7 | 16.0 |
| Prepayments | 6.9 | 5.9 |
| Income taxes receivable | 1.0 | — |
| Other current assets | 3.1 | 2.8 |
| Total current assets | 169.0 | 164.9 |
| Property, plant, and equipment, net (Note 7) | 602.3 | 733.2 |
| Equity investments in unconsolidated affiliates (Note 5) | 163.7 | 266.8 |
| Power purchase agreements and intangible assets, net (Note 9) | 191.2 | 246.2 |
| Goodwill (Note 8) | 21.3 | 36.0 |
| Derivative instruments asset (Notes 13 and 14) | 2.8 | 4.6 |
| Other assets | 8.5 | 5.1 |
| Total assets | $ 1,158.8 | $ 1,456.8 |
| **Liabilities** | | |
| Current liabilities: | | |
| Accounts payable | $ 2.2 | $ 4.5 |
| Accrued interest | 0.3 | 0.7 |
| Other accrued liabilities | 25.5 | 24.4 |
| Current portion of long-term debt (Note 11) | 99.5 | 111.9 |
| Current portion of derivative instruments liability (Notes 13 and 14) | 4.4 | 7.6 |
| Other current liabilities | 1.0 | 1.8 |
| Total current liabilities | 132.9 | 150.9 |
| Long-term debt, net of unamortized discount and deferred financing costs (Note 11) | 616.3 | 749.2 |
| Convertible debentures, net of unamortized deferred financing costs (Note 12) | 105.4 | 100.4 |
| Derivative instruments liability (Notes 13 and 14) | 19.9 | 21.3 |
| Deferred income taxes (Note 15) | 11.7 | 68.3 |
| Power purchase and fuel supply agreement liabilities, net (Note 9) | 24.1 | 25.3 |
| Other long-term liabilities (Note 10) | 51.7 | 55.5 |
| Total liabilities | 962.0 | 1,170.9 |
| **Equity** | | |
| Common shares, no par value, unlimited authorized shares; 115,211,976 and 114,649,888 issued and outstanding at December 31, 2017 and December 31, 2016 (Note 18) | 1,274.8 | 1,272.9 |
| Accumulated other comprehensive loss (Note 4) | (134.8) | (148.5) |
| Retained deficit | (1,158.4) | (1,059.8) |
| Total Atlantic Power Corporation shareholders' equity | (18.4) | 64.6 |
| Preferred shares issued by a subsidiary company (Note 19) | 215.2 | 221.3 |
| Total equity | 196.8 | 285.9 |
| Total liabilities and equity | $ 1,158.8 | $ 1,456.8 |

See accompanying notes to consolidated financial statements.

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

**(in millions of U.S. dollars, except per share amounts)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| Project revenue: | | | |
| Energy sales | $ 148.9 | $ 184.2 | $ 191.5 |
| Energy capacity revenue | 105.8 | 141.9 | 149.3 |
| Other (Note 2) | 176.3 | 73.1 | 79.4 |
| | 431.0 | 399.2 | 420.2 |
| Project expenses: | | | |
| Fuel | 106.3 | 149.5 | 165.1 |
| Operations and maintenance | 87.8 | 105.2 | 103.5 |
| Development | — | — | 1.1 |
| Depreciation and amortization | 113.1 | 113.5 | 110.0 |
| | 307.2 | 368.2 | 379.7 |
| Project other income: | | | |
| Change in fair value of derivative instruments (Notes 13 and 14) | 2.1 | 37.9 | 15.4 |
| Equity in (loss) earnings of unconsolidated affiliates (Note 5) | (54.8) | 35.9 | 36.7 |
| Interest, net | (17.5) | (9.2) | (8.2) |
| Impairment (Notes 8 and 9) | (101.1) | (85.9) | (127.8) |
| Other income, net | 0.1 | 0.4 | 2.0 |
| | (171.2) | (20.9) | (81.9) |
| Project (loss) income | (47.4) | 10.1 | (41.4) |
| Administrative and other expenses: | | | |
| Administration | 23.6 | 22.6 | 29.4 |
| Interest expense, net | 64.2 | 106.0 | 107.1 |
| Foreign exchange loss (gain) (Note 14) | 16.3 | 13.9 | (60.3) |
| Other income, net (Note 12) | (0.4) | (3.9) | (3.1) |
| | 103.7 | 138.6 | 73.1 |
| Loss from operations before income taxes | (151.1) | (128.5) | (114.5) |
| Income tax benefit (Note 15) | (58.1) | (14.6) | (30.4) |
| Loss from continuing operations | (93.0) | (113.9) | (84.1) |
| Net income from discontinued operations, net of tax (Note 3) | — | — | 19.5 |
| Net loss | (93.0) | (113.9) | (64.6) |
| Net loss attributable to noncontrolling interests | — | — | (11.0) |
| Net income attributable to preferred shares of a subsidiary company (Note 14) | 5.6 | 8.5 | 8.8 |
| Net loss attributable to Atlantic Power Corporation | $ (98.6) | $ (122.4) | $ (62.4) |
| Basic and diluted (loss) income per share: (Note 20) | | | |
| Loss from continuing operations attributable to Atlantic Power Corporation | $ (0.86) | $ (1.02) | $ (0.76) |
| Income from discontinued operations, net of tax | — | — | 0.25 |
| Net loss attributable to Atlantic Power Corporation | $ (0.86) | $ (1.02) | $ (0.51) |
| Weighted average number of common shares outstanding: (Note 20) | | | |
| Basic | 115.1 | 119.5 | 121.9 |
| Diluted | 115.1 | 119.5 | 121.9 |
| | | | |
| Dividends per common share: | $ — | $ — | $ 0.09 |

See accompanying notes to consolidated financial statements.

## ATLANTIC POWER CORPORATION

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

## (in millions of U.S. dollars)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Net loss | $ (93.0) | $ (113.9) | $ (64.6) |
| Other comprehensive loss, net of tax: | | | |
| Unrealized loss on hedging activities | $ (0.1) | $ (0.2) | $ (0.6) |
| Net amount reclassified to earnings | 0.5 | 0.7 | 0.7 |
| Net unrealized gain on derivatives | 0.4 | 0.5 | 0.1 |
| Defined benefit plan, net of tax | (0.7) | (0.5) | 1.6 |
| Foreign currency translation adjustments | 14.0 | (9.2) | (72.8) |
| Other comprehensive income (loss), net of tax | 13.7 | (9.2) | (71.1) |
| Comprehensive loss | (79.3) | (123.1) | (135.7) |
| Less: Comprehensive income attributable to preferred shares of a subsidiary company | 5.6 | 8.5 | 8.8 |
| Less: Comprehensive loss attributable to noncontrolling interests | — | — | (11.0) |
| Comprehensive loss attributable to Atlantic Power Corporation | $ (84.9) | $ (131.6) | $ (133.5) |

See accompanying notes to consolidated financial statements.

## ATLANTIC POWER CORPORATION

## CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

## (in millions of U.S. dollars)

| | Common Shares (Shares) | Common Shares (Amount) | Retained Deficit | Accumulated Other Comprehensive Income (loss) | Noncontrolling Interests | Preferred Shares of a Subsidiary Company | Total Shareholders' Equity |
|---|---|---|---|---|---|---|---|
| December 31, 2014 | 121.3 | $ 1,288.4 | $ (863.9) | $ (68.3) | $ 239.0 | $ 221.3 | $ 816.5 |
| Net (loss) income | — | — | (62.4) | — | (11.0) | 8.8 | (64.6) |
| Common shares issued for LTIP | 0.7 | 2.3 | — | — | — | — | 2.3 |
| Common shares issued for DRIP | 0.2 | — | — | — | — | — | — |
| Common share repurchases | (0.1) | (0.1) | — | — | — | — | (0.1) |
| Dividends declared on common shares | — | — | (11.1) | — | — | — | (11.1) |
| Dividends paid to noncontrolling interests | — | — | — | — | (3.7) | — | (3.7) |
| Dividends declared on preferred shares of a subsidiary company | — | — | — | — | — | (8.8) | (8.8) |
| Derecognition of noncontrolling interests upon sale of subsidiaries | — | — | — | — | (224.3) | — | (224.3) |
| Unrealized gain on hedging activities, net of tax of $0.1 million | — | — | — | 0.2 | — | — | 0.2 |
| Foreign currency translation adjustments | — | — | — | (72.8) | — | — | (72.8) |
| Defined benefit plan, net of tax of $0.6 million | — | — | — | 1.6 | — | — | 1.6 |
| December 31, 2015 | 122.1 | $ 1,290.6 | $ (937.4) | $ (139.3) | $ — | $ 221.3 | $ 435.2 |
| Net (loss) income | — | — | (122.4) | — | — | 8.5 | (113.9) |
| Common shares issued for LTIP | 0.5 | 1.8 | — | — | — | — | 1.8 |
| Dividends declared on preferred shares of a subsidiary company | — | — | — | — | — | (8.5) | (8.5) |
| Common share repurchases | (8.0) | (19.5) | — | — | — | — | (19.5) |
| Unrealized gain on hedging activities, net of tax of $0.2 million | — | — | — | 0.5 | — | — | 0.5 |
| Foreign currency translation adjustments | — | — | — | (9.2) | — | — | (9.2) |
| Defined benefit plan, net of tax of $0.2 million | — | — | — | (0.5) | — | — | (0.5) |
| December 31, 2016 | 114.6 | $ 1,272.9 | $ (1,059.8) | $ (148.5) | $ — | $ 221.3 | $ 285.9 |
| Net (loss) income | — | — | (98.6) | — | — | 5.6 | (93.0) |
| Common shares issued for LTIP | 0.7 | 2.1 | — | — | — | — | 2.1 |
| Dividends declared on preferred shares of a subsidiary company | — | — | — | — | — | (8.6) | (8.6) |
| Common share repurchases | (0.1) | (0.2) | — | — | — | — | (0.2) |
| Preferred share repurchases | — | — | — | — | — | (3.1) | (3.1) |
| Unrealized gain on hedging activities, net of tax of $0.3 million | — | — | — | 0.4 | — | — | 0.4 |
| Foreign currency translation adjustments | — | — | — | 14.0 | — | — | 14.0 |
| Defined benefit plan, net of tax of $0.3 million | — | — | — | (0.7) | — | — | (0.7) |
| December 31, 2017 | 115.2 | $ 1,274.8 | $ (1,158.4) | $ (134.8) | $ — | $ 215.2 | $ 196.8 |

See accompanying notes to consolidated financial statements.

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(in millions of U.S. dollars)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Cash provided by operating activities: | | | |
| Net loss | $ (93.0) | $ (113.9) | $ (64.6) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | | |
| Depreciation and amortization | 113.1 | 113.5 | 120.3 |
| Loss (gain) on sale of assets | 0.1 | — | (48.7) |
| Gain on purchase and cancellation of convertible debentures | — | (3.7) | (3.1) |
| Stock-based compensation | 2.1 | 1.8 | 2.3 |
| Long-lived asset and goodwill impairment | 101.1 | 85.9 | 127.8 |
| Equity in loss (earnings) from unconsolidated affiliates | 54.8 | (35.9) | (36.2) |
| Distributions from unconsolidated affiliates | 47.3 | 55.3 | 58.5 |
| Unrealized foreign exchange loss (gain) | 15.2 | 13.8 | (60.5) |
| Change in fair value of derivative instruments | (2.1) | (37.9) | (14.7) |
| Amortization of debt discount and deferred financing costs | 10.8 | 44.6 | 20.5 |
| Change in deferred income taxes | (62.2) | (17.5) | (3.5) |
| Change in other operating balances | | | |
| Accounts receivable | (15.4) | 2.3 | 5.7 |
| Inventory | (1.6) | 0.9 | 2.4 |
| Prepayments and other assets | 0.4 | 5.4 | 0.4 |
| Accounts payable | (0.9) | (0.2) | (8.9) |
| Accruals and other liabilities | (0.5) | (2.1) | (9.4) |
| Cash provided by operating activities | 169.2 | 112.3 | 88.3 |
| Cash provided by (used in) investing activities: | | | |
| Change in restricted cash | 7.1 | 1.9 | 7.3 |
| Proceeds from sale of assets and equity investments, net | 1.0 | — | 326.3 |
| Contribution to unconsolidated affiliate | — | — | (0.6) |
| Capitalized development costs | — | — | (0.8) |
| Reimbursement of costs for third party construction project | — | 4.8 | — |
| Purchase of property, plant and equipment | (5.3) | (7.2) | (11.3) |
| Cash provided by (used in) investing activities | 2.8 | (0.5) | 320.9 |
| Cash used in financing activities: | | | |
| Proceeds from term loan facility, net of discount | — | 679.0 | — |
| Common share repurchases | (0.2) | (19.5) | — |
| Preferred share repurchases | (3.1) | — | — |
| Repayment of corporate and project-level debt | (165.9) | (544.4) | (403.3) |
| Repayment of convertible debentures | — | (188.5) | (18.9) |
| Deferred financing costs | (0.3) | (16.2) | — |
| Dividends paid to common shareholders | | — | (11.1) |
| Dividends paid to noncontrolling interests | | — | (3.7) |
| Cash payments for vested LTIP units withheld for taxes | (0.7) | (0.5) | (0.9) |
| Dividends paid to preferred shareholders | (8.7) | (8.5) | (8.8) |
| Cash used in financing activities: | (178.9) | (98.6) | (446.7) |
| Net (decrease) increase in cash and cash equivalents | (6.9) | 13.2 | (37.5) |
| Cash and cash equivalents at beginning of period at discontinued operations | — | — | 3.9 |
| Cash and cash equivalents at beginning of period | 85.6 | 72.4 | 106.0 |
| Cash and cash equivalents at end of period | $ 78.7 | $ 85.6 | $ 72.4 |
| Supplemental cash flow information | | | |
| Interest paid | $ 72.0 | $ 70.7 | $ 100.0 |
| Income taxes paid, net | $ 4.4 | $ 3.5 | $ 10.2 |
| Accruals for construction in progress | $ 1.2 | $ 1.2 | $ 0.6 |

See accompanying notes to consolidated financial statements.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**(in millions of U.S. dollars, except per-share amounts)**

## 1. Nature of business

### *General*

Atlantic Power is an independent power producer that owns power generation assets in nine states in the United States and two provinces in Canada. Our power generation projects, which are diversified by geography, fuel type, dispatch profile and offtaker, sell electricity to utilities and other large customers predominantly under long-term PPAs, which seek to minimize exposure to changes in commodity prices. As of December 31, 2017, the Company's portfolio consisted of twenty-two projects with an aggregate electric generating capacity of approximately 1,793 megawatts ("MW") on a gross ownership basis and approximately 1,440 MW on a net ownership basis. Eighteen of the projects are majority-owned and operated by the Company. Four of the Company's projects in Ontario are not in operation, two because of contract expirations at December 31, 2017, another due to a revised contractual arrangement with the offtaker, and the fourth, Tunis, has a forward-starting 15-year contractual agreement that will commence with commercial operation of the plant in the third quarter of 2018. The eighteen projects in operation at December 31, 2017 have generating capacity of approximately 1,633 MW on a gross ownership basis and approximately 1,280 MW on a net ownership basis. In early February 2018, the Company's three plants in San Diego, totaling 112 MW on a gross and net ownership basis, ceased operations, as discussed in Note 8, *Goodwill and long-lived asset impairments.*

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at 3 Allied Drive, Suite 220, Dedham, Massachusetts 02026, USA.

## 2. Summary of significant accounting policies

(a) Principles of consolidation and basis of presentation:

The accompanying consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the consolidated accounts and operations of our subsidiaries in which we have a controlling financial interest. The usual condition for a controlling financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity ("VIE"), through arrangements that do not involve controlling voting interests.

We apply the standard that requires consolidation of VIEs, for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party has both the power to direct the activities that most significantly impact the entities' economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. We have determined that our equity investments are not VIEs by evaluating their design and capital structure. Accordingly, we use the equity method of accounting for all of our investments in which we do not have an economic controlling interest. We eliminate all intercompany accounts and transactions in consolidation.

(b) Cash and cash equivalents:

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of 90 days or less when purchased.

(c) Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the projects or corporate to support payments for maintenance costs and meet project level and corporate contractual debt obligations. Restricted cash is classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse.

(d) Accounts receivable:

Accounts Receivable are carried at cost. We periodically assesses the collectability of accounts receivable, considering factors such as specific evaluation of collectability, historical collection experience, the age of accounts receivable and other currently available evidence of the collectability, and record an allowance for doubtful accounts for the estimated uncollectible amount as appropriate. We had no allowance for doubtful accounts recorded at December 31, 2017 and 2016, respectively.

(e) Deferred financing costs:

Deferred financing costs represent costs to obtain long-term financing and are amortized using the effective interest method over the term of the related debt, which ranges from 1 to 6 years. The carrying amount of deferred financing costs were recorded on the consolidated balance sheets as net of long-term debt and convertible debentures and was $11.7 million and $17.8 million at December 31, 2017 and 2016, respectively. Interest expense from the amortization of deferred finance costs for the years ended December 31, 2017, 2016, and 2015 was $6.3 million, $40.8 million, and $20.5 million, respectively.

(f) Inventory:

Inventory represents small parts and other consumables and fuel, the majority of which is consumed by our projects in provision of their services, and are valued at the lower of cost and net realizable value. Cost is the sum of the purchase price and incidental expenditures and charges incurred to bring the inventory to its existing condition or location. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs.

(g) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset. Significant additions or improvements extending asset lives or increasing generating capacity are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred.

(h) Project development costs and capitalized interest:

Project development costs are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, obtaining a PPA.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and depreciated on a straight-line basis over the estimated useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

(i) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects acquired as part of business combinations. PPAs are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the agreement.

(j) Investments accounted for by the equity method:

We have investments in entities that own power-producing assets with the objective of generating cash flow. The equity method of accounting is applied to such investments in affiliates, which include joint ventures, partnerships, and limited liability companies because the ownership structure prevents us from exercising a controlling influence over the operating and financial policies of the projects. Our investments in partnerships and limited liability companies with 50% or less ownership, but greater than 5% ownership in which we do not have a controlling interest are accounted for under the equity method of accounting. We apply the equity method of accounting to investments in limited partnerships and limited liability companies with greater than 5% ownership because our influence over the investment's operating and financial policies is considered to be more than minor.

Under the equity method, equity in pre-tax income or losses of our investments is reflected as equity in earnings of unconsolidated affiliates in the consolidated statements of operations. We apply the nature of distributions method for the classification of our investments accounted for by the equity method in the Consolidated Statements of Cash Flows. The cash flows that are distributed to us from these unconsolidated affiliates are directly related to the operations of the affiliates' power-producing assets and are classified as cash flows from operating activities in the consolidated statements of cash flows. We record the return of our investments in equity investees as cash flows from investing activities. Cash flows from equity investees are considered a return of capital when distributions are generated from proceeds of either the sale of our investment in its entirety or a sale by the investee of all or a portion of its capital assets.

(k) Impairment of long-lived assets, intangible assets and equity method investments:

Long-lived assets, such as property, plant and equipment, and other intangible assets and liabilities subject to depreciation and amortization, are reviewed for impairment annually or whenever events or changes in circumstances indicate that the carrying amount of an asset group may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset group. If the carrying amount of an asset group exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset group exceeds its fair value. Our asset groups have been determined to be at the plant level, which is the lowest level in which independent, separately identifiable cash flows have been identified.

Investments in and the operating results of 50%-or-less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. We also review a project for impairment at the earlier of executing a new PPA (or other arrangement) or six months prior to the expiration of an existing PPA. Factors such as the business climate, including current energy and market conditions, environmental regulation, the condition of assets, and the ability to secure new PPAs are considered when evaluating long-lived assets for impairment. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment or, where applicable, estimated sales proceeds that are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(l) Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is allocated, as of the date of the business combination, to our reporting units that are expected to benefit from the synergies of the business combination.

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired.

In our test, we first perform step zero to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (i.e. more than 50%) that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions, industry and market considerations, cost factors, overall financial performance and other relevant entity-specific events. If the qualitative assessment determines that an impairment is more likely than not, then we perform a quantitative impairment test. In the quantitative analysis, the carrying amount of the reporting unit is compared with its fair value. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired. When the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized in an amount equal to the excess, not to exceed the carrying amount of goodwill, and is recorded in the consolidated statements of operations.

We determine the fair value of our reporting units using an income approach with discounted cash flow models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected merchant power prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our long-lived asset recovery and goodwill impairment tests for our reporting units are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilized estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows of the particular reporting unit and is based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources. We utilized the assistance of valuation experts to perform quantitative impairment tests for several of our reporting units. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

The valuation of long-lived assets and goodwill for the impairment analyses is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities. Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors.

As a result, there can be no assurance that the estimates and assumptions made for purposes of a goodwill impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our reporting units may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long-term forecasts.

(m) Accounts payable and other accrued liabilities:

Accounts payable consists of amounts due to trade creditors related to our core business operations. These payables include amounts owed to vendors and suppliers for items such as fuel, maintenance, inventory and other raw materials. Other accrued liabilities include items such as income taxes, legal contingencies and employee-related costs including payroll, benefits and related taxes.

(n) Assets held for sale and discontinued operations:

For those businesses where we have committed to a plan to divest, each business is valued at the lower of its carrying amount or estimated fair value less cost to sell. If the carrying amount of the business exceeds its estimated fair value, an impairment loss is recognized. Fair value is estimated using accepted valuation techniques such as a discounted cash flow model, valuations performed by third parties, earnings multiples, or indicative bids, when available. A number of significant estimates and assumptions are involved in the application of these techniques, including the forecasting of markets and market share, sales volumes and prices, costs and expenses, and multiple other factors. We consider historical experience and all available information at the time the estimates are made; however, the fair value that is ultimately realized upon the divestiture of a business may differ from the estimated fair value reflected in the consolidated financial statements. Depreciation and amortization expense is not recorded on assets of a business to be divested once they are classified as held for sale. Businesses to be divested are classified in the consolidated financial statements as either discontinued operations or held for sale.

For businesses classified as discontinued operations, the balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities of operations held for sale on the consolidated balance sheet and to discontinued operations on the consolidated statements of operations, respectively, for all periods presented. The gains or losses associated with these divested businesses are recorded in discontinued operations on the consolidated statements of operations. Segment information does not include the assets or operating results of businesses classified as discontinued operations for all periods presented.

(o) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a significant operating cost. We do not enter into derivative financial instruments for trading or speculative purposes. Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales in the ordinary course of conducting business. This exception applies when we have the ability to, and it is probable that we will deliver or take delivery of the underlying physical commodity.

We have designated one of our interest rate swaps as a hedge of cash flows for accounting purposes. Tests are performed to evaluate hedge effectiveness and ineffectiveness at inception and on an ongoing basis, both retroactively and prospectively. Derivatives accounted for as hedges are recorded at fair value in the balance sheet. Unrealized gains or losses on derivatives designated as a hedge for accounting purposes are deferred and recorded as a component of accumulated other comprehensive loss ("OCL") until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

Derivative financial instruments not designated as a hedge for accounting purposes are measured at fair value with changes in fair value recorded in the consolidated statements of operations. Derivative financial instruments under master netting arrangements are recorded net, when applicable, in the consolidated balance sheets. The following table summarizes derivative financial instruments that are not designated as hedges for accounting purposes and the accounting treatment in the consolidated statements of operations of the changes in fair value and cash settlements of such derivative financial instrument:

| Derivative financial instrument | Classification of changes in fair value | Classification of cash settlements |
|---|---|---|
| Natural gas swaps | Changes in fair value of derivative instrument | Fuel expense |
| Fuel purchase agreements | Changes in fair value of derivative instrument | Fuel expense |
| Interest rate swaps | Changes in fair value of derivative instrument | Interest expense |
| Foreign currency forward contract | Foreign exchange (gain) loss | Foreign exchange (gain) loss |

(p) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 15 for more information.

(q) Revenue recognition:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. PPAs, steam purchase arrangements and energy services agreements are long-term contracts to sell power and steam on a predetermined basis.

*Energy*—Energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in our consolidated statements of operations.

*Capacity*—Capacity payments under the PPAs are recognized as the amount billable under the PPA.

*Other*—The primary component of other revenue is composed of steam sales to customers, which is recognized upon delivery to the customer. In addition to steam revenue, Other revenue also includes waste heat revenue, management fees or other contractual payments received not related to energy and capacity under our PPAs.

For the year ended December 31, 2017, Other revenue includes $28.6 million received from a settlement agreement with the OEFC relating to a disagreement over the application of price escalator calculations in our PPAs at North Bay, Kapuskasing and Tunis. Additionally, Other revenue includes $81.2 million of revenue recognized for payments received under enhanced dispatch contracts for our North Bay, Kapuskasing and Nipigon projects. Under the terms of these contracts, these plants are not operational and receive contractual payments over the life of the contracts.

We have entered into PPAs to sell power at predetermined rates. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the project's property, plant and equipment in return for future payments. Such arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as direct financing leases.

Finance income related to leases or arrangements accounted for as direct financing leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is comprised of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying value of the leased property. Unearned finance income is deferred and recognized in net income (loss) over the lease term.

For PPAs accounted for as operating leases, we recognize lease income consistent with the recognition of energy revenue. When energy is delivered, we recognize lease income in energy revenue.

(r) Administrative expenses:

Administrative expenses include corporate and other expenses primarily for executive management, finance, legal, human resources and information systems, which are not directly allocable to our business segments.

(s) Foreign currency translation and transaction gains and losses:

The local currency is the functional currency of our U.S. and Canadian projects. Our reporting currency is the U.S. dollar. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of our statements of operations for the period, but are accumulated and reported as a separate component of shareholders' equity until sale of the net investment in the project takes place. Foreign currency transaction gains or losses are reported within foreign exchange (gain) loss in our consolidated statements of operations.

(t) Equity compensation plans:

The officers and certain other employees are eligible to participate in the Long-Term Incentive Plan ("LTIP"). Vested notional units are expected to be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date.

We initially recognize compensation expense on the estimated number of notional units for which the requisite service is expected to be rendered. We have estimated a weighted average forfeiture rate of 11% for all notional unit grants under the LTIP. This estimate will be revisited if subsequent information indicates the actual number of notional units forfeited is likely to differ from previous estimates. Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards.

(u) Asset retirement obligations:

The fair value for an asset retirement obligation is recorded in the period in which it is incurred. Retirement obligations associated with long-lived assets are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we either settle the obligation for its recorded amount or incur a gain or loss.

(v) Pensions:

We offer pension benefits to certain employees through a defined benefit pension plan. We recognize the funded status of our defined benefit plan in the consolidated balance sheets in other long-term liabilities and record an offset to other comprehensive income (loss). In addition, we also recognize on an after-tax basis, as a component of other comprehensive income (loss), gains and losses as well as all prior service costs that have not been included as part of our net periodic benefit cost. The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets, the rate of future compensation increases and retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of our pension obligation or expense recorded.

(w) Business combinations:

We account for our business combinations in accordance with the acquisition method of accounting, which requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

(x) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative instruments. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to the credit-worthiness and payment history of our customers. See Note 22, *Segment and geographic information*, for a further discussion of customer concentrations.

(y) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations, and the fair values of acquired assets. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(z) Recently adopted and issued accounting standards:

*Accounting Standards Adopted in 2017*

In January 2017, the FASB issued authoritative guidance, which removes the requirement to perform a hypothetical purchase price allocation to measure goodwill impairment. A goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. This guidance is effective for us for annual and interim periods beginning January 1, 2020, with early adoption permitted, and applied prospectively. We early adopted this guidance for our annual goodwill impairment test conducted at November 30, 2017. The estimated fair value of our Curtis Palmer reporting unit was $14.7 million less than its carrying value. Because we early adopted this guidance, we did not perform a hypothetical purchase price allocation and recorded a $14.7 million impairment of goodwill for the year ended December 31, 2017.

In March 2016, the FASB issued authoritative guidance intended to simplify and improve several aspects of the accounting for share-based payment transactions. The new guidance included amendments to share-based accounting for income taxes, including adjustments to how excess tax benefits and a company's payments for tax withholdings should be classified in the statement of cash flows and provides for an entity-wide accounting policy election to either estimate the number of awards that are expected to vest or account for forfeitures when they occur. This guidance became effective for us on January 1, 2017. We elected to continue to estimate forfeitures based on the number of awards that are expected to vest. As a result of the adoption, the cash paid when directly withholding shares for taxwithholding purposes for the LTIP have been classified as a financing activity on the consolidated statement of cash flows. Previously, we classified changes in LTIP liabilities as an operating activity on the consolidated statement of cash flows. This change was applied retrospectively to cash flows provided by operations and cash flows used in financing activities on the consolidated statements of cash flows for the years ended December 31, 2016 and 2015.

In November 2015, the FASB issued changes to the balance sheet classification of deferred taxes. These changes simplified the presentation of deferred income taxes by requiring all deferred income tax assets and liabilities, along with any related valuation allowance, to be classified as noncurrent in a classified balance sheet. The prior requirement that deferred tax assets and liabilities of a tax-paying component of an entity be offset and presented as a single amount was not affected by these changes. This guidance became effective for us on January 1, 2017 and did not have an impact on the consolidated financial statements.

In July 2015, the FASB issued changes to the subsequent measurement of inventory. Prior to these changes, an entity was required to measure its inventory at the lower of cost or market, whereby market can be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. The changes required that inventory be measured at the lower of cost and net realizable value, thereby eliminating the use of the other two market methodologies. Net realizable value is defined as the estimated selling prices in the ordinary course of business less reasonably predictable costs of completion, disposal, and transportation. This guidance became effective for us on January 1, 2017 and did not have an impact on the consolidated financial statements.

*Accounting Standards Not Yet Adopted*

In November 2016, the FASB issued authoritative guidance to address diversity in practice of presenting changes in restricted cash on the statement of cash flows. The new guidance requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. This guidance will change our presentation of restricted cash in the consolidated statements of cash flows upon adoption. If this guidance was adopted for the years ended December 31, 2017, 2016 and 2015, cash flows from investing activities would decrease by $7.1 million, $1.9 million and $7.3 million, respectively.

In October 2016, the FASB issued authoritative guidance, which amends existing guidance related to the recognition of current and deferred incomes taxes for intra-entity asset transfers. Under the new guidance, current and deferred income tax consequences of an intra-entity asset transfer, other than an intra-entity asset transfer of inventory, are now recognized when the transfer occurs. The guidance is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2017 with early adoption permitted. The guidance is not expected to have a material impact on the consolidated financial statements.

In August 2016, the FASB issued authoritative guidance intended to clarify classification of specific cash flows that have aspects of more than one class of cash flows. As a result of this new guidance, entities should be applying specific GAAP in the following eight cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. The guidance is not expected to have a material impact on the consolidated financial statements.

In February 2016, the FASB issued authoritative guidance intended to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new guidance, lessees will be required to recognize a right-of-use asset and a lease liability, measured on a discounted basis, at the commencement date for all leases with terms greater than twelve months. Additionally, this guidance will require disclosures to help investors and other financial statement users to better understand the amount, timing, and uncertainty of cash flows arising from leases, including qualitative and quantitative requirements. The guidance should be applied under a modified retrospective transition approach for leases existing at the beginning of the earliest comparative period presented in the adoption-period financial statements. Any leases that expire before the initial application date will not require any accounting adjustment. This guidance is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. We expect to elect certain of the practical expedients permitted, including the expedient that permits us to retain our existing lease assessment and classification. We are currently working through an adoption plan which includes the evaluation of lease contracts compared to the new standard. While we are currently evaluating the impact the new guidance will have on our financial position and results of operations, we expect to recognize lease liabilities and right of use assets. The extent of the increase to assets and liabilities associated with these amounts remains to be determined pending our review of our existing lease contracts and PPAs currently accounted for as operating leases. As this review is still in process, it is currently not practicable to quantify the impact of adopting this guidance at this time.

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard. The new requirements will be effective for us beginning January 1, 2018, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2018.

Management is substantially complete with its evaluation of the impact of this new guidance on our consolidated financial statements. We developed and executed a project plan to assess the potential impact of the standard and evaluated all of our most significant contracts (PPAs) and other sources of ancillary revenue. We identified thirteen PPAs and one management agreement under which we have recorded revenue that are in scope for this analysis. Further, we identified eight PPAs that were not in scope, seven of which because they terminate prior to the adoption date, and one that it is accounted for as a direct financing lease. For each revenue source in scope, we utilized a five-step approach to apply the standard including (1) identification of the contract(s) with the customer, (2) identification of the separate performance obligations in the contract, (3) determination of the transaction price, (4) allocation of the transaction price to separate performance obligations, and (5) recognition of revenue when (or as) each performance obligation is satisfied.

Under the new standard, revenue is recognized upon the satisfaction of an entity's performance obligations, which occurs when control of a good or service transfers to the customer. Control can transfer either at a point in time or over time. Control over energy, capacity and steam are transferred over time to our customers and the benefits are consumed simultaneously. We applied the output method under the standard to recognize revenue on the basis of direct measurements of the value to the customer of the goods or services transferred to date relative to the remaining goods or services promised under the contract. Further, the new standard includes a practical expedient that allows an entity to recognize revenue in the amount to which the entity has the right to invoice such that the entity has a right to the consideration in an amount that corresponds directly with the value to the customer for performance completed to date by the entity. Currently we recognize energy and steam revenue upon transmission to the customer. Capacity revenue is recognized when billed hours are made available under the terms of the relevant PPA. We determined that output method in the new standard is in line with our current practice of recognizing revenue when invoiced based on actual metered data. Accordingly, the new standard will not impact the consolidated financial statements upon adoption on January 1, 2018 and no cumulative transition adjustment will be recorded.

In May 2017, the FASB issued authoritative guidance to address diversity in practice and cost and complexity of applying the guidance relating to stock compensation to a change to the terms or conditions of a share-based payment award. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. We do not expect this to have a material impact to the consolidated financial statements upon adoption.

In August 2017, the FASB issued authoritative guidance to align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. The guidance expands and refines hedge accounting for both nonfinancial and financial risk components and aligns the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. The guidance is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We are currently evaluating the potential impact of the adoption on the consolidated financial statements.

**3. Divestments**

***2017 Divestments***

(a) Selkirk Project

On November 2017, we sold our 17.7% interest in Selkirk Cogen Partners, LP ("Selkirk") to JMC Selkirk LLC, the project's majority owner, for $1.0 million. Selkirk was accounted for under the equity method of accounting. In the second quarter of 2017, we recorded a $10.6 million impairment at Selkirk and wrote our equity investment down to zero. As a result of the sale, we recorded a $1.0 million gain on sale, which is included as a component of (loss) income from unconsolidated affiliates in the consolidated statement of operations for the year ended December 31, 2017.

***2015 Divestments***

(a) Wind Projects

On March 31, 2015, Atlantic Power Transmission ("APT"), our wholly-owned, direct subsidiary, entered into a purchase agreement with TerraForm AP Acquisition Holdings, LLC ("TerraForm"), an affiliate of SunEdison, Inc., to sell our Wind Projects. On June 26, 2015, the sale was completed for aggregate cash proceeds of approximately $335 million after transaction fees, exclusive of transaction-related taxes. We recorded a $46.8 million gain on sale, which is included as a component of income from discontinued operations in the consolidated statements of operations for the year ended December 31, 2015.

Terraform acquired from APT, 100% of APT's direct membership interests in a holding company formed to facilitate the sale, thereby acquiring our indirect interests in our portfolio of Wind Projects consisting of five operating wind projects in Idaho and Oklahoma and representing 521 MW net ownership: Goshen (12.5% economic interest), Idaho Wind (27.6% economic interest), Meadow Creek (100% economic interest); Rockland Wind Farm (50% economic interest, but consolidated on a 100% basis); and Canadian Hills (99% economic interest). As a result of the sale, we deconsolidated approximately $249 million of project debt (or approximately $274 million as adjusted for our proportional ownership of Rockland, Goshen North and Idaho Wind) and approximately $224 million of non-controlling interest related to tax equity interests at Canadian Hills and the minority ownership interests at Rockland and Canadian Hills.

The Wind Projects were designated as assets held for sale and discontinued operations on March 31, 2015, the date we established a firm commitment to a plan to sell the wind assets. Our determination to designate the Wind Projects as discontinued operations was based on the impact the sale will have on our operations and financial results and because the Wind Projects made up the entirety of our Wind Reportable Segment. We stopped depreciating the property, plant and equipment of the Wind Projects on the designation date.

(b) Frontier

On April 22, 2015, our indirect wholly-owned subsidiary, Ridgeline Energy LLC (''Ridgeline'), closed a transaction with CRE-Frontier Solar California LLC (''CRE''), a subsidiary of Centaurus Renewable Energy LLC, whereby CRE agreed to purchase 100% of Ridgeline's equity interests in Frontier Solar, LLC (''Frontier''), which is developing an approximately 20 MW solar electric generating facility in California, for net cash proceeds of $4.3 million. We recorded a $2.3 million gain on sale related to the transaction in other income in the consolidated statements of operations for the year ended December 31, 2015. Frontier is not accounted for as a component of discontinued operations.

(in millions of U.S. dollars, except per-share amounts)

### 4. Changes in accumulated other comprehensive loss by component

The changes in accumulated OCL by component are as follows:

| | Year Ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|
| **Foreign currency translation** | | | |
| Balance at beginning of period | $ (148.3) | $ (139.1) | $ (66.3) |
| Other comprehensive loss: | | | |
| Foreign currency translation adjustments[1] | 14.0 | (9.2) | (72.8) |
| Balance at end of period | $ (134.3) | $ (148.3) | $ (139.1) |
| **Pension** | | | |
| Balance at beginning of period | $ (0.9) | $ (0.4) | $ (2.1) |
| Other comprehensive loss: | | | |
| Unrecognized net actuarial (loss) gain | (1.6) | (0.7) | 2.2 |
| Tax benefit (expense) | 0.4 | 0.2 | (0.6) |
| Total Other comprehensive (loss) income before reclassifications, net of tax | (1.2) | (0.5) | 1.6 |
| Total amount reclassified from accumulated other comprehensive loss, net of tax | 0.5 | — | 0.1 |
| Total other comprehensive (loss) income | (0.7) | (0.5) | 1.7 |
| Balance at end of period | $ (1.6) | $ (0.9) | $ (0.4) |
| **Cash flow hedges** | | | |
| Balance at beginning of period | $ 0.7 | $ 0.2 | $ 0.1 |
| Other comprehensive loss: | | | |
| Net change from periodic revaluations | (0.2) | (0.3) | (1.0) |
| Tax benefit | 0.1 | 0.1 | 0.4 |
| Total Other comprehensive loss before reclassifications, net of tax | (0.1) | (0.2) | (0.6) |
| Net amount reclassified to earnings: | | | |
| Interest rate swaps[2] | 0.9 | 1.0 | 1.3 |
| Tax expense | (0.4) | (0.3) | (0.6) |
| Total amount reclassified from accumulated other comprehensive loss, net of tax | 0.5 | 0.7 | 0.7 |
| Total other comprehensive income | 0.4 | 0.5 | 0.1 |
| Balance at end of period | $ 1.1 | $ 0.7 | $ 0.2 |

(1) In all periods presented, there were no tax impacts related to rate changes and no amounts were reclassified to earnings (loss).

(2) This amount was included in interest expense, net on the accompanying consolidated statements of operations.

(in millions of U.S. dollars, except per-share amounts)

## 5. Equity method investments in unconsolidated affiliates

The following tables summarize our equity method investments in unconsolidated affiliates:

| Entity name | Percentage of Ownership as of December 31, 2017 | Carrying value as of December 31, 2017 | Carrying value as of December 31, 2016 |
|---|---|---|---|
| Frederickson[1] | 50.2 % | $ 77.3 | $ 115.3 |
| Orlando Cogen, LP | 50.0 % | 7.0 | 7.3 |
| Koma Kulshan Associates | 49.8 % | 4.9 | 5.0 |
| Chambers Cogen, LP | 40.0 % | 74.5 | 127.6 |
| Selkirk Cogen Partners, LP [2] | — % | — | 11.6 |
| Total | | $ 163.7 | $ 266.8 |

(1) We own 50.15% of Frederickson. However, we do not have financial control of the entity. The Frederickson entity is organized under a joint ownership agreement. Under the terms of that agreement, the two owner parties have joint control and substantive participating rights through the structure of its Owner's Committee. Each party has equal representation on this committee and unanimous consent is required over all significant decisions of the entity. These significant decisions include, but are not limited to (i) approval of the annual operating plan, annual operating budget, annual capital budget and five-year forecasts, (ii) approval of all expenditures in excess of the approved budget, (iii) adoption of procedures intended to govern the operation and conduct of the facility, and (iv) entering into, amending, supplementing or terminating any project agreement. Disputes between the owners for these significant decisions are subject to independent arbitration. Accordingly, since we do not control the project, Frederickson is accounted for under the equity method of accounting.

(2) In November 2017, we sold our 17.7% interest in Selkirk.

Deficit in earnings of equity method investments, net of distributions, was as follows:

| Entity name | Year Ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|
| Frederickson | $ (27.9) | $ 2.2 | $ 2.6 |
| Orlando Cogen, LP | 25.6 | 27.8 | 27.0 |
| Koma Kulshan Associates | 0.7 | 0.8 | 0.4 |
| Chambers Cogen, LP | (42.6) | 5.5 | 6.5 |
| Selkirk Cogen Partners, LP | (10.6) | (0.4) | 0.2 |
| Total (loss) earnings of unconsolidated affiliates | (54.8) | 35.9 | 36.7 |
| Distributions from equity method investments | (47.3) | (55.3) | (58.5) |
| (Deficit) excess in earnings of equity method investments, net of distributions | $ (102.1) | $ (19.4) | $ (21.8) |

Distributions from equity method investments exceeded (loss) earnings of equity method investments for the years ended December 31, 2017, 2016 and 2015, respectively. Distributions from our equity method investments are typically based on project-level cash flows from operations or other non-GAAP metrics, whereas equity earnings include non-cash expenses such as depreciation and amortization, investment impairments or changes in the fair value of derivative financial instruments.

(in millions of U.S. dollars, except per-share amounts)

The following summarizes the financial position at December 31, 2017, 2016 and 2015, and operating results for the years ended December 31, 2017, 2016 and 2015, respectively, for our proportional ownership interest in equity method investments:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Frederickson | $ 1.9 | $ 1.7 | $ 1.8 |
| Orlando Cogen, LP | 9.2 | 7.5 | 10.0 |
| Koma Kulshan Associates | 0.5 | 0.6 | 0.7 |
| Chambers Cogen, LP | 17.3 | 15.0 | 15.0 |
| Selkirk Cogen Partners, LP | — | 11.3 | 11.5 |
| Non-current assets | | | |
| Frederickson | 76.2 | 114.1 | 124.0 |
| Orlando Cogen, LP | 8.1 | 9.1 | 10.2 |
| Koma Kulshan Associates | 4.7 | 5.0 | 5.3 |
| Chambers Cogen, LP | 130.9 | 190.0 | 201.7 |
| Selkirk Cogen Partners, LP | — | 2.4 | 2.2 |
| | $ 248.8 | $ 356.7 | $ 382.4 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Frederickson | $ 0.4 | $ 0.1 | $ 0.7 |
| Orlando Cogen, LP | 10.3 | 9.2 | 11.7 |
| Koma Kulshan Associates | 0.1 | 0.1 | 0.6 |
| Chambers Cogen, LP | 3.7 | 3.8 | 3.7 |
| Selkirk Cogen Partners, LP | — | 0.6 | — |
| Non-current liabilities | | | |
| Frederickson | 0.4 | 0.5 | 0.4 |
| Orlando Cogen, LP | — | — | — |
| Koma Kulshan Associates | 0.2 | 0.5 | 0.5 |
| Chambers Cogen, LP | 70.0 | 73.6 | 77.3 |
| Selkirk Cogen Partners, LP | — | 1.5 | 1.3 |
| | $ 85.1 | $ 89.9 | $ 96.2 |

**(in millions of U.S. dollars, except per-share amounts)**

| **Operating results** | **2017** | **2016** | **2015** |
|---|---|---|---|
| Revenue | | | |
| Frederickson | $ 21.6 | $ 20.7 | $ 21.6 |
| Orlando Cogen, LP | 55.0 | 54.6 | 54.1 |
| Koma Kulshan Associates | 1.8 | 1.9 | 1.5 |
| Chambers Cogen, LP | 43.8 | 44.7 | 48.0 |
| Selkirk Cogen Partners, LP | 1.8 | 7.9 | 11.6 |
| | 124.0 | 129.8 | 136.8 |
| Project expenses | | | |
| Frederickson | 21.0 | 18.5 | 19.0 |
| Orlando Cogen, LP | 29.4 | 26.9 | 27.1 |
| Koma Kulshan Associates | 1.1 | 1.1 | 1.1 |
| Chambers Cogen, LP | 37.5 | 37.4 | 39.7 |
| Selkirk Cogen Partners, LP | 2.8 | 8.2 | 11.6 |
| | 91.8 | 92.1 | 98.5 |
| Project other expense | | | |
| Frederickson | (28.4) | — | — |
| Orlando Cogen, LP | — | — | — |
| Koma Kulshan Associates | — | — | — |
| Chambers Cogen, LP | (48.9) | (1.8) | (1.8) |
| Selkirk Cogen Partners, LP | (9.7) | — | 0.2 |
| | (87.0) | (1.8) | (1.6) |
| Project (loss) income | | | |
| Frederickson | (27.8) | 2.2 | 2.6 |
| Orlando Cogen, LP | 25.6 | 27.7 | 27.0 |
| Koma Kulshan Associates | 0.7 | 0.8 | 0.4 |
| Chambers Cogen, LP | (42.6) | 5.5 | 6.5 |
| Selkirk Cogen Partners, LP | (10.7) | (0.3) | 0.2 |
| Equity in (loss) earnings of unconsolidated affiliates | $ (54.8) | $ 35.9 | $ 36.7 |

We recorded investment impairments of $47.1 million, $28.3 million and $10.6 million, respectively, at our Chambers, Frederickson and Selkirk projects in the year ended December 31, 2017. These impairments are a component of the operating results in the table above.

2017 – Event-driven test in the fourth quarter

*Frederickson*

In the fourth quarter of 2017, we performed an impairment test of our investment in our Frederickson project. The Frederickson project operates under three PPAs that expire in August 2022. Prior to our impairment analysis, Frederickson was recorded as a $108.3 million component of our equity investments in unconsolidated affiliates on the consolidated balance sheets. Excluding impairment, we have recorded equity earnings of $0.4 million, $2.2 million and $2.6 million for the years ended December 31, 2017, 2016 and 2015, respectively at Frederickson. During those periods, we also received cumulative cash distributions of $34.7 million.

We performed an analysis of the post-PPA value of Frederickson operating as a merchant facility. While declining power prices have been observed over the past several years, in our most recent long-term forecast completed in December 2017, we identified a significant decrease in the long-term peak demand outlook for power prices in the

Pacific Northwest, the region where Frederickson operates, which management determined to be an other than temporary decline in prices. These forward prices, which were obtained from a third party, had a significant negative impact on the estimated discounted cash flows of Frederickson post-PPA. The estimated post-PPA value is a significant component of the project's overall value when compared to its pre-impairment carrying value of $108.3 million.

Frederickson passed its investment impairment test performed in the fourth quarter of 2016. When determining if the decrease in fair value estimated in our 2017 test is other than temporary, we considered the likelihood that future conditions would change such that the power prices currently observed in the forward pricing models would become more favorable over time. Frederickson operates in a region with large, planned coal facility retirements and strong population growth. However, it is our assessment that natural gas prices are likely to remain low when considering the current and expected future supply of shale gas and that these factors would negatively impact future merchant pricing. Based on these factors, we determined that the decline in the fair value of our equity investment in Frederickson is other than temporary. We recorded a $28.3 million impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the year ended December 31, 2017.

*2017 – Event-driven test in the second quarter*

In the second quarter of 2017, we performed event-driven impairment tests of our investments in our Chambers and Selkirk projects, which are accounted for under the equity method of accounting.

*Selkirk*

We previously owned a 17.7% limited partner interest in Selkirk Cogen Partners, L.P. The project operated as a merchant facility since the expiration of its PPA in August 2014. Since the expiration of its PPA, we did not receive a distribution from Selkirk and recorded a cumulative $2.6 million project loss. Based on the project's history of providing no cash distributions while operating as a merchant facility, the short-term and long-term operational forecast, as well as the likelihood that further investment would be required in order to operate the facility, we determined that our investment in Selkirk was impaired and the decline in value was other than temporary. Accordingly, we recorded a $10.6 million full impairment in earnings from unconsolidated affiliates in the consolidated statements of operations in the three months ended June 30, 2017. We sold our interest in Selkirk in November 2017 and recorded a $1 million gain on sale in the year ended December 31, 2017. The impairment charge and the gain in sale are both recorded in earnings from unconsolidated affiliates in the statement of operations for the year ended December 31, 2017.

*Chambers*

We own a 40% limited partner interest in Chambers Cogeneration Limited Partnership. The Chambers project operates under a PPA that expires in March 2024. Prior to our impairment analysis, Chambers was recorded as a $124 million component of our equity investments in unconsolidated affiliates on the consolidated balance sheets. We recorded equity earnings of $3.4 million, $5.5 million and $6.5 million for the six months ended June 30, 2017, year ended December 31, 2016 and year ended December 31, 2015, respectively. During those periods, we also received cumulative distributions of $33.6 million from Chambers.

During the second quarter of 2017, we performed an analysis of the post-PPA value of Chambers operating as a merchant facility. While declining power prices have been observed over the past several years, in our most recent long-term forecast completed in July 2017, we identified a significant decrease in the long-term outlook for power prices in PJM, the region where Chambers operates, which management determined to be an other than temporary decline in prices. These forward power prices, which were obtained from a third party, including analysis of the forward prices for natural gas and coal, had a significant negative impact on the estimated discounted cash flows ("DCFs") of Chambers post-PPA. The estimated post-PPA value is a significant component of the project's overall value when compared to its carrying value of $124 million.

(in millions of U.S. dollars, except per-share amounts)

Chambers passed its investment impairment test performed in the fourth quarter of 2016. When determining if this decrease in fair value estimated in our event-driven 2017 test is other than temporary, we considered the likelihood that future conditions would change such that the gas and coal prices currently observed in the forward pricing models would become more favorable over time in order for the plant to be profitable in a merchant market. We also engaged a separate third party to provide its outlook on post-PPA value for Chambers. It is our assessment that future merchant pricing is likely to remain low due to lower natural gas prices from the current and expected future supply of shale gas. The third party provided similar conclusions to our assessment.

Based on these factors, we determined that the decline in the fair value of our equity investment in Chambers is other than temporary. We recorded a $47.1 million impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the three months ended June 30, 2017.

## 6. Inventory

Inventory consists of the following:

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| Parts and other consumables | $ 12.1 | $ 10.0 |
| Fuel | 5.6 | 6.0 |
| Total inventory | $ 17.7 | $ 16.0 |

## 7. Property, plant and equipment, net

Property, plant and equipment, net consists of the following:

| | December 31, 2017 | December 31, 2016 | Depreciable Lives |
|---|---|---|---|
| Land | $ 5.5 | $ 5.3 | |
| Office equipment, machinery and other | 6.0 | 5.6 | 3 - 10 years |
| Leasehold improvements | 2.2 | 2.2 | 7 - 15 years |
| Asset retirement obligation | 28.4 | 27.7 | 1 - 43 years |
| Plant in service | 942.5 | 981.1 | 1 - 45 years |
| | 984.6 | 1,021.9 | |
| Less accumulated depreciation | (382.3) | (288.7) | |
| Total property, plant and equipment, net | $ 602.3 | $ 733.2 | |

Depreciation expense of $83.3 million, $49.5 million and $59.0 million, was recorded for the years ended December 31, 2017, 2016 and 2015, respectively.

As described in Note 8, *Goodwill and long-lived asset impairment*, we recorded $67.6 million and $5.9 million of long-lived asset impairments to property, plant and equipment in the years ended December 31, 2017 and 2016, respectively.

(in millions of U.S. dollars, except per-share amounts)

## 8. Goodwill and long-lived asset impairment

*Goodwill Rollforward*

The following table is a rollforward of goodwill for the years ended December 31, 2017 and 2016:

| Reporting unit | Segment | December 31, 2016 | Impairment | Translation adjustment | December 31, 2017 |
|---|---|---|---|---|---|
| Curtis Palmer | East U.S. | $ 29.1 | $ (14.7) | $ — | $ 14.4 |
| Morris | East U.S. | 3.3 | — | — | 3.3 |
| Nipigon | Canada | 3.6 | — | — | 3.6 |
| | | $ 36.0 | $ (14.7) | $ — | $ 21.3 |

| Reporting unit | Segment | December 31, 2015 | Impairment | Translation adjustment | December 31, 2016 |
|---|---|---|---|---|---|
| Curtis Palmer | East U.S. | $ 44.5 | $ (15.4) | $ — | $ 29.1 |
| Morris | East U.S. | 3.3 | — | — | 3.3 |
| Kapuskasing | Canada | 8.8 | (6.7) | (2.1) | — |
| Mamquam | Canada | 64.4 | (50.2) | (14.2) | — |
| Moresby Lake | Canada | 1.6 | (1.2) | (0.4) | — |
| Nipigon | Canada | 3.6 | — | — | 3.6 |
| North Bay | Canada | 8.3 | (6.5) | (1.8) | — |
| | | $ 134.5 | $ (80.0) | $ (18.5) | $ 36.0 |

*2017 – Annual test performed in fourth quarter*

In the fourth quarter of 2017, we performed our annual goodwill impairment test as of November 30, 2017. Of the remaining reporting units with goodwill recorded, Nipigon ($3.6 million of goodwill at December 31, 2017) and Morris ($3.3 million of goodwill at December 31, 2017) had fair values that exceeded their carrying values by approximately $111.7 million or 118% and accordingly, no goodwill impairment was recorded.

*Curtis Palmer - Goodwill*

In applying the goodwill test, the Curtis Palmer reporting unit's carrying value exceeded its estimated fair value by $14.7 million at November 30, 2017. Accordingly, we recorded a $14.7 million goodwill impairment at Curtis Palmer in the year ended December 31, 2017. Subsequent to the impairment, Curtis Palmer has $14.4 million of goodwill remaining at December 31, 2017. As a hydro facility, Curtis Palmer has substantial useful life beyond the expiration of its PPA in 2027. Estimates of fair value beyond the end of its PPA expiration utilize merchant pricing assumptions and are sensitive to changes in forward power prices. These forward prices have declined significantly over the past year resulting in a reduction of fair value from our impairment test performed in the fourth quarter of 2016.

*Williams Lake – Long-lived assets*

Williams Lake operates under a PPA that expires on March 31, 2018 with BC Hydro. BC Hydro elected not to exercise its renewal options under that PPA. The Province of British Columbia is also commencing an Integrated Resource Plan Process (IRP) in late 2018. This process is the Province's long-term plan to meet future electricity demand through conservation, generation and transmission and through upgrades to existing infrastructure. We believe that obtaining a long-term PPA extension prior to the conclusion of the IRP is unlikely. In January 2018, the project entered into a PPA extension that begins on April 1, 2018 and expires June 30, 2019, or September 30, 2019 at the option of BC Hydro. The project entered into this extension in order to bridge the period of the expiration of our current PPA in March 2018 until the conclusion of the IRP in order to increase the likelihood for the potential of a future long-term extension. The uncertainty of the results of the IRP resulted in a triggering event to test for long-lived asset impairment. We performed the test as of December 31, 2017 in order to include the economics of the January 2018 extension in our long-term cash flow forecasts as the terms of the extension were known at December 31, 2017. Williams Lake's asset group for testing of long-lived assets totaled $40.0 million consisting of $39.4 million in PPE, net and a $0.6 million intangible PPA asset.

Because of the uncertainty of the results of the IRP, we performed a probability-based approach when determining the weighted average fair value of Williams Lake. This approach considered the cash flows under the January 2018 extension, as well as a modeled long-term extension post-IRP incorporating similar economics to the 2018 extension with some additional allowances. These factors incorporated significant judgments and estimates by management when determining outcome likelihood, as well as long-term extension economics. Williams Lake has approximately 22 years of remaining useful life. We believe that Williams Lake provides value to the Province's long-term plan based on its positioning as a renewable resource, its synergy with the local forestry industry and its lower $/KW cost than new biomass construction.

Upon testing Williams Lake for long-lived asset impairment, the carrying value of the asset group exceeded the estimated weighted-average undiscounted cash flows. Because Williams Lake failed the recovery test, we calculated the estimated weighted-average fair value utilizing a probability-based DCF and recorded a $29.1 million long-lived asset impairment in the year ended December 31, 2017, which is the difference between the fair value and carrying value of the reporting unit's asset group. The impairment was allocated as a $0.6 million full impairment of intangible PPA assets and a $28.5 million partial impairment of property, plant and equipment.

*2017 – Event-driven test in the third quarter*

In the third quarter of 2017, we performed event-driven long-lived asset impairment tests at Naval Station, North Island and Naval Training Center ("NTC") (collectively, the "San Diego Projects").

The San Diego Projects sell power to San Diego Gas & Electric ("SDG&E") under PPAs that are scheduled to expire in December 2019. In addition, the three projects supply steam to the U.S. Navy under agreements that provide these projects with the right to use the property at the respective sites on which each project is located (the "Navy agreements"). In August 2017, we were unsuccessful in obtaining contracts to provide the Navy with energy security that would have provided us with the right to use the Naval Station and North Island sites beyond February 2018. Following notification of the outcome of the Navy solicitation, we determined that it was unlikely that these projects will operate beyond the expiration of the Navy agreements. As a result, we performed long-lived asset impairment tests at each of these projects as of July 31, 2017.

In order to test the recoverability of the long-lived assets in the asset groups, we compared the carrying amount of the assets to estimated undiscounted future cash flows expected to be generated by each of the San Diego Projects through their expected decommissioning dates. The carrying value of each asset group includes its recorded property, plant equipment and intangible assets related to PPAs. As a result of this test, we recorded a total $57.3 million impairment ($22.5 million at Naval Station, $13.5 million at NTC and $21.2 million at North Island) in the year ended December 31, 2017. This impairment is composed of an $18.2 million full impairment of intangible assets related to PPAs ($10.3 million at Naval Station, $3.6 million at NTC and $4.2 million at North Island) and a $39.1 million partial impairment of property, plant and equipment ($12.1 million at Naval Station, $9.9 million at NTC and $17.0 million at North Island). At December 31, 2017, the San Diego projects' remaining property, plant and equipment, which represents our estimate of the projects' remaining undiscounted cash flows and salvage values.

We were unable to extend our land use license agreements through the end of our PPAs and ceased operations at these plants on February 7, 2018.

*2016 – Annual test performed in fourth quarter*

In the fourth quarter of 2016, we performed our annual goodwill impairment test as of November 30, 2016. Of the total remaining reporting units with goodwill recorded, Curtis Palmer ($29.1 million of goodwill at December 31, 2016) and Nipigon ($3.6 million of goodwill at December 31, 2016) passed step 1 of the two-step test. The total fair value of these reporting units exceeded their carrying value by approximately $62.7 million or 45%. For our Morris reporting unit, we performed a qualitative assessment and concluded that it was likely that the fair value significantly exceeded the reporting unit's carrying value. The Morris reporting unit has goodwill of $3.3 million and has a PPA with significant remaining time before its expiration and is not significantly impacted by the decrease in the long-term outlook for power prices.

The Moresby Lake reporting units failed step 1 of the two-step test. Accordingly, we performed a step 2 analysis for Moresby Lake and, as a result, recorded a $1.2 million full impairment in the year ended December 31, 2016. Moresby Lake has substantial useful life beyond the expiration of its PPA in 2022. However, Moresby Lake's fair value is estimated using a discounted cash flow approach and is sensitive to changes in forward power prices. These forward prices have declined significantly over the past several years. Moresby failed step 1 in our event-driven impairment test at July 31, 2016, but recorded no impairment as its implied goodwill exceeded its recorded goodwill. The further decline in forward power prices since our event-driven test resulted in the full impairment recorded at November 30, 2016.

*2016 – Event-driven test in the third quarter*

In the third quarter of 2016, we performed an event-driven goodwill impairment test as of July 31, 2016. While declining power prices have been observed over the past two years, we identified a significant decrease in the long-term outlook for power prices in the regions where our reporting units operate in the third quarter of 2016. Because the estimated future cash flows of our reporting units are sensitive to fluctuations in forward power prices and these prices are the most impactful input in calculating a reporting unit's fair value, we determined that it was appropriate to perform an event-driven impairment test. For two of our reporting units (Morris and Nipigon) we performed a qualitative assessment and concluded that it was likely that the fair values significantly exceed the carrying values. These reporting units have aggregate goodwill of $6.9 million and have PPAs with significant remaining time before their expiration and are not significantly impacted by the decrease in the long-term outlook for power prices.

The other five of the reporting units tested (Curtis Palmer, Mamquam, North Bay, Kapuskasing and Moresby Lake) failed step 1 of our quantitative two-step test. Because five reporting units failed step 1 of the two-step goodwill impairment test, we identified a triggering event and initiated a test of the recoverability of their long-lived assets. The asset group for testing the long-lived assets for impairment is the same as the reporting unit for goodwill impairment testing purposes. In order to test the recoverability of the assets in the asset groups, we compared the carrying amount of the assets to estimated undiscounted future cash flows expected to be generated by the asset group. The carrying value of each asset group includes its recorded property, plant equipment, intangible assets related to PPAs and goodwill. Of the five asset groups tested, the North Bay and Kapuskasing asset groups (Canada segment) failed the recoverability test and we recorded property, plant and equipment impairment charges aggregating $5.9 million for the periods ended September 30, 2016. For these asset groups, we estimated their fair value utilizing an income approach based on market participant assumptions. These assumptions include estimated cash flows under the remaining period of their respective PPAs.

(in millions of U.S. dollars, except per-share amounts)

Subsequent to recording long-lived asset impairments, we performed the step 2 goodwill impairment test and recorded a $50.2 million full impairment at the Mamquam reporting unit, a $15.4 million partial impairment at the Curtis Palmer reporting unit, a $6.5 million full impairment at the North Bay reporting unit, a $6.7 million full impairment at the Kapuskasing reporting unit and no impairment at the Moresby Lake reporting unit for a total goodwill impairment charge of $78.8 million for the period ended September 30, 2016. At the time of their acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Mamquam and Curtis Palmer reporting units were valued assuming a merchant basis for the period subsequent to the expiration of the projects' original PPAs. The forecasted energy revenue on a merchant basis, in the respective markets in which those plants operate, was higher than the energy prices currently forecasted to be in effect subsequent to the expiration of the reporting unit's PPA. Power prices, in the respective markets in which those plants operate, have declined from 2011 and from the dates of our previous impairment assessments due to several factors including decreased demand, lower oil prices and lower natural gas prices resulting from an abundance of shale gas. Our forecasts for discounted cash flows also reflect a higher level of uncertainty for re-contracting at prices than were previously forecasted in 2011. The decline in forward power prices for British Columbia since our last goodwill impairment performed as of November 30, 2015, in particular, had a significant impact on the estimated discounted cash flows of our Mamquam reporting unit and was the primary driver for its recorded goodwill impairment. British Columbia's peak demand outlook has declined primarily attributable to a reduction in forecasted liquefaction build and need in the region and the associated loss of power demand. The resulting drop in the peak demand reduces the amount of needed capacity and therefore the capacity prices also were reduced. Furthermore, the PPA at the Curtis Palmer reporting unit expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. Based on Curtis Palmer's cumulative generation through the date of the goodwill impairment test, we anticipate the PPA expiring two years before December 2027. As a result, the discounted cash flow model for Curtis Palmer utilizes forward power prices for that two-year period that are substantially lower than the prices under the current PPA.

The long-lived asset and goodwill impairment charges were recorded in the third quarter of 2016 and not earlier in the fiscal year because we did not identify any triggering events that would have required an event-driven impairment assessment. Although declining power prices had been observed over the two years prior to the impairment, the significant decrease in the long-term outlook for power prices in the regions where our reporting units operate identified in the third quarter of 2016 had the most significant impact to the key inputs to our long-term forecasted cash flow models. Additionally, the PPAs at our North Bay and Kapuskasing reporting units expire on December 31, 2017. As these projects approach the expiration date, the remaining estimated contracted future cash flows decrease.

The following tables provide a summary of impairment charges by type for the years ended December 31, 2017 and 2016, respectively:

| | Year Ended December 31, 2017 | | | | | |
|---|---|---|---|---|---|---|
| | Curtis Palmer | Williams Lake | Naval Station | North Island | Naval Training Center | Total |
| Goodwill | $ 14.7 | $ — | $ — | $ — | $ — | $ 14.7 |
| Property, plant and equipment | — | 28.5 | 12.1 | 17.0 | 10.0 | 67.6 |
| Power purchase agreement intangible assets | — | 0.6 | 10.4 | 4.2 | 3.6 | 18.8 |
| Total | $ 14.7 | $ 29.1 | $ 22.5 | $ 21.2 | $ 13.6 | $ 101.1 |

(in millions of U.S. dollars, except per-share amounts)

| | Year Ended December 31, 2016 | | | | | |
|---|---|---|---|---|---|---|
| | Curtis Palmer | Mamquam | Kapuskasing | North Bay | Moresby Lake | Total |
| Goodwill | $ 15.4 | $ 50.2 | $ 6.7 | $ 6.5 | $ 1.2 | $ 80.0 |
| Property, plant and equipment | — | — | 2.1 | 3.8 | — | 5.9 |
| Power purchase agreement intangible assets | — | — | — | — | — | — |
| Total | $ 15.4 | $ 50.2 | $ 8.8 | $ 10.3 | $ 1.2 | $ 85.9 |

**9. PPAs and other intangible assets and liabilities**

Other intangible assets and liabilities include PPAs, fuel supply agreements and capitalized development costs.

As described in Note 8, *Goodwill and long-lived asset impairment*, we recorded $18.8 million of long-lived asset impairments to PPA intangible assets for the year ended December 31, 2017.

The following tables summarize the components of our intangible assets and other liabilities subject to amortization at December 31, 2017 and 2016:

*Assets*

| | Other Intangible Assets, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Development Costs | Total |
| Gross balances, December 31, 2017 | $ 476.3 | $ 13.0 | $ 489.3 |
| Less: accumulated amortization | (285.1) | (13.0) | (298.1) |
| Net carrying amounts, December 31, 2017 | $ 191.2 | $ — | $ 191.2 |

| | Other Intangible Assets, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Development Costs | Total |
| Gross balances, December 31, 2016 | $ 538.7 | $ 13.0 | $ 551.7 |
| Less: accumulated amortization | (292.7) | (12.8) | (305.5) |
| Net carrying amounts, December 31, 2016 | $ 246.0 | $ 0.2 | $ 246.2 |

*Liabilities*

| | Power Purchase and Fuel Supply Agreement Liabilities, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Fuel Supply Agreements | Total |
| Gross balances, December 31, 2017 | $ (30.4) | $ (12.6) | $ (43.0) |
| Less: accumulated amortization | 11.6 | 7.3 | 18.9 |
| Net carrying amounts, December 31, 2017 | $ (18.8) | $ (5.3) | $ (24.1) |

(in millions of U.S. dollars, except per-share amounts)

| | Power Purchase and Fuel Supply Agreement Liabilities, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Fuel Supply Agreements | Total |
| Gross balances, December 31, 2016 | $ (29.0) | $ (12.6) | $ (41.6) |
| Less: accumulated amortization | 11.0 | 5.3 | 16.3 |
| Net carrying amounts, December 31, 2016 | $ (18.0) | $ (7.3) | $ (25.3) |

The following table presents amortization expense of intangible assets for the years ended December 31, 2017, 2016 and 2015:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| PPAs | $ 36.5 | $ 63.3 | $ 51.3 |
| Fuel supply agreements | (0.4) | (0.4) | (1.2) |
| Total amortization | $ 36.1 | $ 62.9 | $ 50.1 |

The following table presents estimated future amortization expense for the next five years related to PPAs and fuel supply agreements:

| Year Ended December 31, | Power Purchase Agreements | Fuel Supply Agreements |
|---|---|---|
| 2018 | $ 50.6 | $ (0.4) |
| 2019 | 27.7 | (0.4) |
| 2020 | 27.7 | (0.4) |
| 2021 | 24.4 | (0.4) |
| 2022 | 21.8 | (0.4) |

The following table presents the weighted amortization period related to our intangible assets as of December 31, 2017:

| As of December 31, 2017 | Power Purchase Agreements | Fuel Supply Agreements |
|---|---|---|
| **(in years)** | | |
| Weighted average remaining amortization period | 10.0 | 17.0 |

## 10. Other long-term liabilities

Other long-term liabilities consist of the following at December 31:

| | 2017 | 2016 |
|---|---|---|
| Asset retirement obligations | $ 45.3 | $ 50.3 |
| Net pension liability | 1.9 | 1.3 |
| Accrued LTIP and director share units | 2.2 | 1.7 |
| Other | 2.3 | 2.2 |
| | $ 51.7 | $ 55.5 |

(in millions of U.S. dollars, except per-share amounts)

The following table is a rollforward of asset retirement obligations for the years ended December 31:

| | 2017 | 2016 |
|---|---|---|
| Asset retirement obligations beginning of year | $ 50.3 | $ 48.5 |
| Accretion and change in estimate of asset retirement obligation | (6.5) | 1.2 |
| Translation adjustments | 1.5 | 0.6 |
| Asset retirement obligations, end of year | $ 45.3 | $ 50.3 |

In the third quarter of 2017, we performed an event-driven long-lived asset impairment test at our Naval Station, North Island and Naval Training Center projects. See Note 8, *Goodwill and long-lived asset impairment* for discussion of the facts and circumstances resulting in the impairment. At the time of the assessment, we had not completed our process for estimating decommissioning costs at those facilities. In the fourth quarter of 2017, based on information provided by third parties, we determined that the estimated costs to remove the facilities and return the land to the conditions required under their respective land rights agreements was approximately $1.7 million. Prior to adjustment, we had recorded asset retirement obligations for Naval Station, North Island and Naval Training Center of $6.7 million. These retirement obligations were based on estimates made at the time of their acquisition in November 2011, as well as engineering studies performed at the inception of these projects. These asset retirement obligations were accreted based on inflation and discount rates that were not adjusted subsequent to the acquisition date. As a result of the change in estimate for decommissioning costs, we recorded a $5.0 million decrease to amortization expense in the fourth quarter of 2017.

## 11. Long-term debt

Long-term debt consists of the following:

| | December 31, 2017 | December 31, 2016 | Interest Rate | |
|---|---|---|---|---|
| **Recourse Debt:** | | | | |
| Senior secured term loan facility, due 2023(1) | $ 540.0 | $ 639.9 | LIBOR(2) plus | 3.50 % |
| Senior unsecured notes, due June 2036 (Cdn$210.0) | 167.4 | 156.4 | | 5.95 % |
| **Non-Recourse Debt:** | | | | |
| Epsilon Power Partners term facility, due 2019 | 7.2 | 13.5 | LIBOR plus | 3.125 % |
| Cadillac term loan, due 2025 (3) | 24.0 | 27.0 | LIBOR plus | 1.49 % |
| Piedmont term loan, due 2018 | — | 56.6 | LIBOR plus | 3.75 % |
| Other long-term debt | 0.1 | 0.2 | 5.50 % - | 6.70 % |
| Less: unamortized discount | (12.8) | (17.2) | | |
| Less: unamortized deferred financing costs | (10.1) | (15.3) | | |
| Less: current maturities | (99.5) | (111.9) | | |
| Total long-term debt | $ 616.3 | $ 749.2 | | |

(in millions of U.S. dollars, except per-share amounts)

Current maturities consist of the following:

| | December 31, 2017 | December 31, 2016 | Interest Rate | |
|---|---|---|---|---|
| **Current Maturities:** | | | | |
| Senior secured term loan facility, due 2023[1] | $ 90.0 | $ 100.0 | LIBOR[2] plus | 3.50 % |
| Epsilon Power Partners term facility, due 2019 | 6.5 | 6.2 | LIBOR plus | 3.125 % |
| Cadillac term loan, due 2025 [3] | 3.0 | 3.0 | LIBOR plus | 1.49 % |
| Piedmont term loan, due 2018 | — | 2.5 | LIBOR plus | 3.75 % |
| Other short-term debt | — | 0.2 | 5.50 % - | 6.70 % |
| Total current maturities | $ 99.5 | $ 111.9 | | |

(1) On a quarterly basis, we make a cash sweep payment to fund the principal balance, based on terms as defined in the credit agreement and disclosed below. The portion of the Term Loan facility classified as current is based on principal payments required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule.

(2) LIBOR cannot be less than 1.00%. We have entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $354.2 million of the $540 million outstanding aggregate borrowings under our Term Loan facility at December 31, 2017. See Note 14, *Accounting for derivative instruments and hedging activities* for further details.

(3) We have entered into interest rate swap agreements to economically fix our exposure to changes in interest rates for this non-recourse debt. See Note 14, *Accounting for derivative instruments and hedging activities*, for further details.

Principal payments on the maturities of our debt due in the next five years and thereafter are as follows:

| | |
|---|---|
| 2018 | $ 99.5 |
| 2019 | 68.8 |
| 2020 | 108.1 |
| 2021 | 82.7 |
| 2022 | 78.3 |
| Thereafter | 301.3 |
| | $ 738.7 |

***Credit Facilities***

On April 13, 2016, APLP Holdings Limited Partnership ("APLP Holdings"), our wholly-owned subsidiary, entered into new Senior Secured Credit Facilities, comprising $700 million in aggregate principal amount of Senior Secured Term Loan facilities (the "Term Loans") and $200 million in aggregate principal amount of senior secured credit facilities (the "Revolver" and together with the Term Loans, the "Credit Facilities"). At December 31, 2017, $540.0 million of the Term Loans is outstanding and letters of credit in an aggregate face amount of $80.5 million are issued (but not drawn) pursuant to the revolving commitments under the Revolver and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service, and (ii) to support contractual credit support obligations of APLP Holdings and its subsidiaries and of certain other affiliates of the Company.

Borrowings under Credit Facilities are available in U.S. dollars and Canadian dollars and, at inception, bore interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate as applicable, plus an applicable margin between 4.00% and 5.00% that varied depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. In April 2017, the repricing of the Credit Facilities became effective reducing the interest rate margin on the term loan and revolver by 0.75% to LIBOR plus 4.25%. In October 2017, a second repricing reduced the interest rate margin on the Credit Facilities by another 0.75% to LIBOR plus 3.50%. We also extended the maturity date of the Revolver by one year through April 2022. The Term Loans mature in April 2023.

The Term Loans include a 3% original issue discount. Letters of credit are available to be issued under the Revolver until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. In addition to paying interest on outstanding principal under the Credit Facilities, APLP Holdings is required to pay a commitment fee of 0.75% times the unused commitments under the Revolver.

The Credit Facilities are secured by a pledge of the equity interests in APLP Holdings and certain of its subsidiaries, guaranties from certain of the subsidiaries of APLP Holdings (the "Subsidiary Guarantors"), a downstream guarantee from the Company, a limited recourse guaranty from Atlantic Power GP II, Inc., the entity that holds all of the equity interest in APLP Holdings, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of APLP Holdings and its subsidiaries (subject to certain exceptions), and certain other assets. The Credit Facilities also have the benefit of a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The reserve requirement is maintained utilizing a letter of credit. APLP, a wholly-owned, indirect subsidiary of the Company, is a party to an existing indenture governing its Cdn$210 million aggregate principal amount of MTNs that prohibits APLP (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, APLP Holdings has granted an equal and ratable security interest in the collateral package securing the New Credit Facilities in favor of the trustee under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The negative covenants include a requirement that APLP Holdings and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 at December 2017 to 4.25:1.00 from June 30, 2020, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 3.00:1.00 at December 31, 2017 to 4.00:1.00 from June 30, 2022. At December 31, 2017, we were incompliance with these covenants. In addition, the Credit Agreement includes customary restrictions and limitations on APLP Holdings' and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to certain exceptions and other customary carve-outs and various thresholds. Specifically, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the new term loan that declines quarterly based on a predetermined specified schedule.

Under the Credit Agreement, if a Change of Control (as defined in the Credit Agreement) occurs, unless APLP Holdings elects to make a voluntary prepayment of the term loans under the Credit Facilities, it will be required to offer each electing lender a prepayment of such lender's term loans under the Credit Facilities at a price equal to 101% of par. In addition, in the event that APLP Holdings elects to repay, prepay, refinance or replace all or any portion of the term loan facilities within six months from the repricing date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid, refinanced or replaced.

The Credit Agreement also contains a mandatory amortization feature and other mandatory prepayment provisions, including prepayments:

- from the proceeds of asset sales (except from the sale proceeds of certain excluded projects), insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and

- with respect to excess cash flows, to be determined by using the greater of (i) 50% of the cash flow of APLP Holdings and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the Credit Facilities and the MTNs, funding of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Failure to achieve the specified target principal amount for any quarter does not constitute a default by APLP Holdings.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of APLP Holdings and its subsidiaries, bankruptcy, material judgments rendered against APLP Holdings or certain of its subsidiaries, certain ERISA or regulatory events, a Change of Control of APLP Holdings (solely with respect to the Revolver), or defaults under certain guaranties and collateral documents securing the Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

***Notes of the Partnership***

The Partnership, a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($167.4 million as of December 31, 2017) aggregate principal amount of 5.95% senior unsecured notes, due June 2036 (MTNs). Interest on the MTNs is payable semi-annually at 5.95%. Pursuant to the terms of the MTNs, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. At December 31, 2017, we were in compliance with these covenants. The MTNs are guaranteed by Atlantic Power Corporation and Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership.

**(in millions of U.S. dollars, except per-share amounts)**

***Non-Recourse Debt***

Project-level debt at our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met in order to distribute available cash. At December 31, 2017, all of our projects were in compliance with the covenants contained in project-level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but the debt is not callable or subject to acceleration under the terms of their debt agreements.

On October 13, 2017, we repaid the $54.6 million Piedmont term loan due August 2018, in full, with cash on hand. In addition to the principal repayment, we paid $0.1 million of accrued interest, $9.4 million to terminate interest rate swap agreements and wrote off $0.9 million of deferred financing costs. The swap termination costs and deferred financing costs write down was recorded as interest expense in the year ended December 31, 2017.

**12. Convertible debentures**

The following table provides details related to outstanding convertible debentures:

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| 5.75% Debentures due June 2019 | 42.5 | 42.6 |
| 6.00% Debentures due December 2019 (Cdn $81.0 million) | 64.5 | 60.3 |
| Less: Unamortized deferred financing costs | (1.6) | (2.5) |
| Total convertible debentures | $ 105.4 | $ 100.4 |

At December 31, 2017, we had $42.5 million principal outstanding 5.75% Debentures due June 2019 (the “Series C Debentures”). We pay interest semi-annually on the last day of June and December of each year for the Series C Debentures. They are convertible into our common shares at an initial conversion rate of 57.9710 common shares per $1,000 principal amount, representing a conversion price of $17.25 per common share. At December 31, 2017, we also had $64.5 million (Cdn$81.0 million) principal amount outstanding 6.00% Debentures due December 2019 (the “Series D Debentures”). We pay interest semi-annually on the last day of June and December of each year for the Series D Debentures. They are convertible into our common shares at an initial conversion rate of 68.9655 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$14.50 per common share.

On December 29, 2015, we commenced a Normal Course Issuer Bid (“NCIB”), which expired on December 28, 2016. On April 13, 2016, we deposited a portion of the proceeds from the issuance of the Credit Facilities, for the redemption in whole on May 13, 2016 at a price equal to par plus accrued interest (i) the outstanding Cdn$67.2 million 6.25% Debentures due March 2017 and (ii) the outstanding Cdn$75.8 million 5.60% Debentures due June 2017. On June 17, 2016, we commenced a substantial issuer bid (“SIB”) to purchase for cancellation up to $65.0 million aggregate principal amount of our issued and outstanding Series C Debentures. As a result of the NCIB, the SIB and the redemptions made with proceeds from the Credit Facilities, we made payments of $188.5 million to redeem and cancel the 6.25% Debentures due March 2017 and the 5.60% Debentures due June 2017, in full, and the Series C Debentures and the Series D Debentures, in part. As a result of these repurchases and cancellations, we recorded a gain of $3.7 million in the consolidated statement of operations for the year ended December 31, 2016. Additionally, we wrote off $2.7 million of deferred financing costs related to the convertible debentures which was recorded to interest expense for the year ended December 31, 2016.

On December 8, 2017, our Board of Directors approved a new NCIB for each series of our convertible unsecured subordinated debentures. Under the NCIB, our broker may purchase up to $4.3 million principal amount of the Series C Debentures and Cdn$8.1 million of the Series D Debentures. The Board authorization permits us to repurchase convertible debentures through open market repurchases. The NCIBs commenced on December 29, 2017 and will expire on December 28, 2018.

On January 29, 2018, we closed the Series E Debentures Offering of Cdn$100 million aggregate principal amount of Series E Debentures. We also granted the underwriters the option to purchase up to an additional Cdn$15 million aggregate principal amount of Series E Debentures at any time up to 30 days after the date of closing of the Series E Debentures offering to cover over-allotments. The underwriters exercised that option, for the full Cdn$15 million aggregate principal amount, on February 2, 2018.

On the initial closing date, we received net proceeds from the Series E Debentures offering, after deducting the underwriting fee and expenses, of approximately Cdn$94.7 million. We received an additional Cdn$14.4 million of net proceeds from the exercise of the over-allotment option. On January 29, 2018, we issued a notice to redeem on all of the $42.5 million remaining principal amount of Series C Debentures with the use of a portion of the proceeds from the Series E Debentures Offering. On February 2, 2018 we issued a notice to redeem Cdn$56.2 million principal amount of the Series D Debentures with the remaining proceeds from the Series E Debentures Offering. After the partial redemption, Cdn$24.7 million aggregate principal amount of the Series D Debentures remain outstanding.

The Series E Debentures have a maturity date of January 31, 2025. The Series E Debentures bear interest at a rate of 6.00% per year, and are convertible into our common shares at an initial conversion rate of approximately 238.0952 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$4.20 per common share.

The Series E Debentures may not be redeemed by the Company prior to January 31, 2021 (except in certain limited circumstances following a change of control). On and after January 31, 2021 and prior to January 31, 2023, the Series E Debentures may be redeemed by us, in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption, provided that the daily volume-weighted average trading price of our common shares on the Toronto Stock Exchange, averaged for the 20 consecutive trading days ending five trading days prior to the date on which notice of redemption is provided, is not less than 125% of the conversion price at the time notice of redemption is given. On and after January 31, 2023 and prior to the maturity date, the Series E Debentures may be redeemed in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice, at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption.

The Series E Debentures are our direct, subordinated, unsecured obligations and rank equally with the other series of debentures and with all other future subordinated unsecured indebtedness and will rank subordinate to all of our existing and future senior indebtedness.

(in millions of U.S. dollars, except per-share amounts)

## 13. Fair value of financial instruments

The estimated carrying values and fair values of our recorded financial instruments related to operations are as follows:

| | December 31, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents | $ 78.7 | $ 78.7 | $ 85.6 | $ 85.6 |
| Restricted cash | 6.2 | 6.2 | 13.3 | 13.3 |
| Derivative assets current | 2.7 | 2.7 | 4.0 | 4.0 |
| Derivative assets non-current | 2.8 | 2.8 | 4.6 | 4.6 |
| Derivative liabilities current | 4.4 | 4.4 | 7.6 | 7.6 |
| Derivative liabilities non-current | 19.9 | 19.9 | 21.3 | 21.3 |
| Long-term debt, including current portion | 738.7 | 749.3 | 893.6 | 826.0 |
| Convertible debentures | 107.0 | 108.1 | 102.9 | 102.0 |

Our financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

The three levels of the fair value hierarchy are defined below:

Level 1—Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange-traded securities.

Level 2—Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3—Unobservable inputs from objective sources. These inputs may be based on entity-specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of December 31, 2017 and December 31, 2016. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

| | December 31, 2017 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $ 78.7 | $ — | $ — | $ 78.7 |
| Restricted cash | 6.2 | — | — | 6.2 |
| Derivative instruments asset | — | 5.5 | — | 5.5 |
| Total | $ 84.9 | $ 5.5 | $ — | $ 90.4 |
| Liabilities: | | | | |
| Derivative instruments liability | $ — | $ 24.3 | $ — | $ 24.3 |
| Total | $ — | $ 24.3 | $ — | $ 24.3 |

(in millions of U.S. dollars, except per-share amounts)

| | December 31, 2016 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $ 85.6 | $ — | $ — | $ 85.6 |
| Restricted cash | 13.3 | — | — | 13.3 |
| Derivative instruments asset | — | 8.6 | — | 8.6 |
| Total | $ 98.9 | $ 8.6 | $ — | $ 107.5 |
| Liabilities: | | | | |
| Derivative instruments liability | $ — | $ 28.9 | $ — | $ 28.9 |
| Total | $ — | $ 28.9 | $ — | $ 28.9 |

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of December 31, 2017, the credit valuation adjustments resulted in a $2.2 million net increase in fair value, which consists of a $0.2 million pre-tax gain in other comprehensive income and a $2.0 million gain in change in fair value of derivative instruments. As of December 31, 2016, the credit valuation adjustments resulted in a $3.8 million net increase in fair value, which consists of a $0.3 million pre-tax gain in other comprehensive income and a $3.5 million gain in change in fair value of derivative instruments.

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature. The fair value of long-term debt and convertible debentures was determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which we could issue debt with a similar maturity as of the balance sheet date.

**14. Accounting for derivative instruments and hedging activities**

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective portion of the change in fair value of the derivatives in accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings (loss). The ineffective portion of a cash flow hedge is immediately recognized in earnings (loss). For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings (loss). These guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

*Gas purchase and sale agreements*

We have a gas purchase agreement at our Nipigon project that expires on December 31, 2022 under which we purchase a minimum of 6,500 Gigajoules (“Gj”) of natural gas per day at a price of Cdn$4.57 per Gj. We also entered into a gas sales agreement fort our Nipigon project under which we sell 6,500 Gj of natural gas per day at a price of Cdn$2.75 that expires on October 31, 2018. We have also entered into natural gas sales agreements at Morris for approximately 220,000 Mmbtu that expires in February 2018. These agreements do not qualify for the normal purchase normal sales (“NPNS”) exemption and are accounted for as derivative financial instruments because we could not conclude that it is probable that these contracts will not settle net and will result in physical delivery. These derivative financial instruments are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

*Natural gas swaps*

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

We have entered into various natural gas swaps to effectively fix the price of 9.9 million Mmbtu of future natural gas purchases at Orlando, which is approximately 90%, 100% and 50% of our share of the expected natural gas purchases at the project in 2018, 2019 and 2020, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2017. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

*Interest rate swaps*

APLP Holdings has entered into several interest rate swap agreements to mitigate its exposure to changes in interest at the Adjusted Eurodollar Rate. At December 31, 2017, these agreements totaled $354.2 million notional amount of the remaining $540.0 million aggregate principal amount of borrowings under the Term Loans. These interest rate swap agreements expire at various dates through March 31, 2020. Borrowings under the $700.0 million Term Loans bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.50%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 4.50% all-in rate on the Term Loan Facility for the non-swapped portion of the remaining principal amount. The weighted average rate of these swap agreements is 1.10% resulting in an all-in rate of approximately 4.60% for $354.2 million of the Term Loans. In January 2018, APLP Holdings entered into additional interest rate swap agreements. For the period beginning June 30, 2018 through September 30, 2019, we mitigated exposure to changes in interest rates for $100 million notional amount at a one-month LIBOR fixed rate of 2.18% and for the period beginning October 1, 2019 through December 31, 2020, for $200 million notional amount at a one-month LIBOR fixed rate of 2.42%.

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.0% through February 15, 2019, 6.3% from February 16, 2019 to February 15, 2023, and 6.4% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and the effective portion of the changes in the fair market value is recorded in accumulated other comprehensive loss.

*Foreign currency forward contracts*

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates as we generate cash flow in U.S. dollars and Canadian dollars. We currently have Canadian dollar payment obligations for preferred dividends, interest on our Canadian dollar-denominated convertible debentures and our Medium Term Notes. Principal and interest payments for our senior secured term loans as well as our U.S dollar-denominated convertible debenture are made in U.S. dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the future interest and principal payments, preferred dividends and other working capital requirements.

In July 2017, we entered into foreign exchange forward contracts to sell a total of Cdn$10 million at an exchange rate of 1.2481 in Cdn$3.3 million tranches on each of March 2018, June 2018 and December 2018. In July 2017, we also entered into foreign exchange forward contracts to sell a total of Cdn$10 million at an exchange rate of

**(in millions of U.S. dollars, except per-share amounts)**

1.2943 in tranches of Cdn$5.0 million in March 2018, Cdn$3.0 million in June 2018 and Cdn$2.0 million in December 2018. In September 2017, we entered into foreign exchange forward contracts to sell Cdn$5.0 million at an exchange rate of 1.2196 in September 2018.

Foreign currency forward contracts are not designated as hedges, and changes in their market value are recorded in foreign exchange on the consolidated statements of operations at December 31, 2017.

*Volume of forecasted transactions*

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the NPNS exemption at December 31, 2017 and December 31, 2016:

| | Units | December 31, 2017 | December 31, 2016 |
|---|---|---|---|
| Natural gas swaps | Natural Gas (Mmbtu) | 9.9 | 4.9 |
| Gas purchase agreements | Natural Gas (Gigajoules) | 9.9 | 11.3 |
| Interest rate swaps | Interest (US$) | 412.6 | 506.9 |
| Foreign currency forward contracts | Dollars (Cdn$) | 25.0 | — |

*Fair value of derivative instruments*

We have elected to disclose derivative instrument assets and liabilities on a trade-by-trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

| | December 31, 2017 | |
|---|---|---|
| | Derivative Assets | Derivative Liabilities |
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swaps current | $ — | $ 0.6 |
| Interest rate swaps long-term | — | 1.5 |
| Total derivative instruments designated as cash flow hedges | — | 2.1 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swaps current | 2.7 | — |
| Interest rate swaps long-term | 2.8 | — |
| Natural gas swaps current | — | 0.8 |
| Natural gas swaps long-term | — | 0.2 |
| Gas purchase agreements current | — | 2.9 |
| Gas purchase agreements long-term | — | 18.2 |
| Foreign currency forward contracts current | — | 0.1 |
| Total derivative instruments not designated as cash flow hedges | 5.5 | 22.2 |
| Total derivative instruments | $ 5.5 | $ 24.3 |

(in millions of U.S. dollars, except per-share amounts)

| | December 31, 2016 | |
|---|---|---|
| | Derivative Assets | Derivative Liabilities |
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swaps current | $ — | $ 0.8 |
| Interest rate swaps long-term | — | 2.0 |
| Total derivative instruments designated as cash flow hedges | — | 2.8 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swaps current | 0.4 | 1.9 |
| Interest rate swaps long-term | 4.5 | 6.5 |
| Natural gas swaps current | 3.9 | 0.8 |
| Natural gas swaps long-term | 0.1 | — |
| Gas purchase agreements current | — | 4.5 |
| Gas purchase agreements long-term | — | 12.7 |
| Total derivative instruments not designated as cash flow hedges | 8.9 | 26.4 |
| Total derivative instruments | $ 8.9 | $ 29.2 |

*Accumulated other comprehensive income*

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

| Year Ended December 31, 2017 | Interest Rate Swaps |
|---|---|
| Accumulated OCI balance at January 1, 2017 | $ 0.7 |
| Change in fair value of cash flow hedges | (0.1) |
| Realized from OCI during the period | 0.5 |
| Accumulated OCI balance at December 31, 2017 | $ 1.1 |
| Settlements expected to be recognized from OCI in expense in the next 12 months, net of $0.2 million of tax | $ 0.7 |

| Year Ended December 31, 2016 | Interest Rate Swaps |
|---|---|
| Accumulated OCI balance at January 1, 2016 | $ 0.2 |
| Change in fair value of cash flow hedges | (0.2) |
| Realized from OCI during the period | 0.7 |
| Accumulated OCI balance at December 31, 2016 | $ 0.7 |

| For the year ended December 31, 2015 | Interest Rate Swaps |
|---|---|
| Accumulated OCI balance at January 1, 2015 | $ 0.1 |
| Change in fair value of cash flow hedges | (0.6) |
| Realized from OCI during the period | 0.7 |
| Accumulated OCI balance at December 31, 2015 | $ 0.2 |

(in millions of U.S. dollars, except per-share amounts)

*Impact of derivative instruments on the consolidated statements of operations*

The following table summarizes realized loss (gain) for derivative instruments not designated as cash flow hedges:

| | Classification of loss (gain) recognized in income | Year Ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|---|
| Gas purchase agreements | Fuel | $ 7.5 | $ 48.5 | $ 47.3 |
| Natural gas swaps | Fuel | 0.4 | 4.9 | 6.0 |
| Interest rate swaps | Interest, net | 0.9 | 3.9 | 3.8 |

The following table summarizes the unrealized gain (loss) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

| | Classification of gain (loss) recognized in income | Year ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|---|
| Natural gas swaps | Change in fair value of derivatives | $ (1.8) | $ 9.0 | $ 1.0 |
| Gas purchase agreements | Change in fair value of derivatives | (5.0) | 22.8 | 16.1 |
| Interest rate swaps | Change in fair value of derivatives | 8.9 | 6.1 | (1.7) |
| | | $ 2.1 | $ 37.9 | $ 15.4 |
| Foreign currency forwards | Foreign exchange loss | $ 0.1 | $ — | $ (1.1) |

## 15. Income tax benefit

The following table summarizes the current and deferred portions of the net income tax benefit:

| | Year Ended December 31 2017 | 2016 | 2015 |
|---|---|---|---|
| Current income tax expense | $ 4.1 | $ 2.9 | $ 5.3 |
| Deferred income benefit | (62.2) | (17.5) | (35.7) |
| Total income tax benefit, net | $ (58.1) | $ (14.6) | $ (30.4) |

(in millions of U.S. dollars, except per-share amounts)

The following is a reconciliation of the income taxes calculated at the Canadian enacted statutory rate of 26% for the years ended December 31, 2017, 2016 and 2015, respectively, to the provision for income taxes in the consolidated statements of operations:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Loss from continuing operations before income taxes | $ (151.1) | $ (128.5) | $ (114.5) |
| Computed income taxes at 26% Canadian statutory rate | (39.3) | (33.4) | (29.8) |
| Decreases resulting from: | | | |
| Operating countries with different income tax rates | (20.1) | (2.9) | (4.9) |
| | (59.4) | (36.3) | (34.7) |
| Change in valuation allowance | (34.6) | 10.8 | 6.6 |
| | (94.0) | (25.5) | (28.1) |
| Dividend withholding tax and other cash taxes | 0.2 | (0.4) | 1.1 |
| Foreign exchange | (2.4) | 6.9 | (7.0) |
| Changes in tax rates | (1.5) | (1.5) | 2.1 |
| Remeasurement of deferred tax assets and liabilities | 28.5 | — | — |
| Production tax credits | — | — | (3.6) |
| Changes in estimates due to tax filings | 1.0 | 1.3 | (6.3) |
| Capital (loss) gain on intercompany notes | (0.1) | (0.2) | 2.1 |
| Impairments | 9.9 | 22.3 | 14.8 |
| Capital loss recognized on tax restructuring | — | (18.0) | — |
| Intra-period allocations from the Wind projects | — | — | (5.0) |
| Other | 0.3 | 0.5 | (0.5) |
| | 35.9 | 10.9 | (2.3) |
| Income tax benefit | $ (58.1) | $ (14.6) | $ (30.4) |
| Effective income tax rate | (38)% | (11)% | (27)% |

**(in millions of U.S. dollars, except per-share amounts)**

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2017 and 2016 are presented below:

| | 2017 | 2016 |
|---|---|---|
| Deferred tax assets: | | |
| Loss carryforwards | $ 157.7 | $ 226.2 |
| Capital loss carryforwards | 35.4 | 33.9 |
| Finance and share issuance costs | 3.0 | 3.4 |
| Tax credits | 1.4 | 4.7 |
| LTIP | 2.8 | 4.0 |
| Derivative contracts | 4.0 | 4.7 |
| Other long-term notes | 1.1 | 0.5 |
| Other | 2.2 | 6.5 |
| Total deferred tax assets | 207.6 | 283.9 |
| Valuation allowance | (151.4) | (186.0) |
| | 56.2 | 97.9 |
| Deferred tax liabilities: | | |
| Intangible assets | (27.9) | (72.0) |
| Property, plant and equipment | (40.0) | (94.2) |
| Total deferred tax liabilities | (67.9) | (166.2) |
| Net deferred tax liability | $ (11.7) | $ (68.3) |

The following table summarizes the net deferred tax position as of December 31, 2017 and 2016:

| | 2017 | 2016 |
|---|---|---|
| Long-term deferred tax liabilities | $ (11.7) | $ (68.3) |
| Net deferred tax liability | $ (11.7) | $ (68.3) |

As of December 31, 2017, we have recorded a valuation allowance of $151.4 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. Some of these loss carryforwards may be subject to limitation on their use. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax asset will be realized. The ultimate realization of the deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

Tax benefits related to uncertain tax positions taken or expected to be taken on a tax return are recorded when such benefits meet a more likely than not threshold. Otherwise, these tax benefits are recorded when a tax position has been effectively settled, which means that the statute of limitation has expired or the appropriate taxing authority has completed their examination even though the statute of limitations remains open. Interest and penalties related to uncertain tax positions are recognized as part of the provision for income taxes and are accrued beginning in the period that such interest and penalties would be applicable under relevant tax law until such time that the related tax benefits are recognized. As of December 31, 2017, we have not recorded any tax benefits related to uncertain tax positions.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law making significant changes to the Internal Revenue Code. Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017, new limitations on the deduction of net business interest expense, and a new base erosion and anti-abuse tax. After preliminary estimates based on guidance available as of the date of this filing, the interest expense limitation and base erosion and anti-abuse tax are not expected to have a material impact to cash taxes in future tax years. The primary item impacting the tax rate for the twelve months ended December

**(in millions of U.S. dollars, except per-share amounts)**

31, 2017 is the amount related to the remeasurement of deferred tax assets and liabilities, based on the rates at which they are expected to reverse in the future for $28.5 million. In addition, the rate was further impacted by $9.9 million related to goodwill impairment. These items were offset by $34.6 million related to a net decrease to our valuation allowances, consisting primarily of decreases of $34.1 million in the United States due to the remeasurement of deferred tax assets and a decrease of $0.5 million in Canada related to income. In addition, the rate was further impacted by $20.1 million relating to operating in higher tax rate jurisdictions, $2.4 million relating to foreign exchange and $0.1 million relating to other permanent differences.

As of December 31, 2017, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

| | |
|---|---|
| 2027 | $ 12.1 |
| 2028 | 60.3 |
| 2029 | 63.8 |
| 2030 | 25.8 |
| 2031 | 13.4 |
| 2032 | 25.3 |
| 2033 | 153.0 |
| 2034 | 167.8 |
| 2035 | 17.0 |
| 2036 | 37.6 |
| 2037 | 16.1 |
| | $ 592.2 |

(in millions of U.S. dollars, except per-share amounts)

## 16. Equity compensation plans

*Long-term incentive plan ("LTIP")*

The following table summarizes the changes in outstanding LTIP notional units during the years ended December 31, 2017, 2016 and 2015:

| | Units | Grant Date Weighted-Average Fair Value per Unit |
|---|---|---|
| Outstanding at December 31, 2014 | 1,443,254 | 3.28 |
| Granted | 1,007,726 | 2.75 |
| Additional shares from dividends | 59,996 | 2.87 |
| Forfeitures | (136,894) | 3.75 |
| Vested and redeemed | (1,075,681) | 3.21 |
| Outstanding at December 31, 2015 | 1,298,401 | 2.88 |
| Granted | 1,594,954 | 1.81 |
| Vested and redeemed | (784,806) | 2.83 |
| Forfeitures | (7,431) | 2.71 |
| Outstanding at December 31, 2016 | 2,101,118 | 2.08 |
| Granted | 1,817,463 | 2.38 |
| Vested and redeemed | (1,009,780) | 2.22 |
| Forfeitures | (24,227) | 2.32 |
| Outstanding at December 31, 2017 | 2,884,574 | $ 2.22 |

The total grant date fair value of all outstanding notional units under the LTIP was $6.4 million, $4.4 million and $3.7 million for the years ended December 31, 2017, 2016 and 2015. The weighted average remaining vesting term for outstanding notional units was 0.9 year at December 31, 2017. Approximately $1.8 million of total unrecognized compensation expense is expected to be recognized over this time period. Compensation expense related to LTIP was $3.4 million, $2.8 million and $3.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. Cash payments made for vested notional units were $0.7 million, $0.5 million and $0.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

*Transition Equity Participation Agreement*

We also have 539,904 transition notional shares outstanding at December 31, 2017 under the Transition Equity Participation Agreement with James J. Moore, Jr. Fifty percent of the transition notional shares granted with respect to fiscal year 2015 will vest upon the four-year anniversary of the date of grant and the remaining portion will vest on or any time after the two-year anniversary of the grant if the weighted average Canadian dollar closing price of our common shares on the TSX for at least three consecutive calendar months has exceeded the market price per common share determined as of January 22, 2015 (Cdn$3.18) by at least 50%.

## 17. Employee benefit plans

***Defined benefit pension plan***

We sponsor and operate a defined benefit pension plan that is available to certain legacy employees of Atlantic Power Limited. The Atlantic Power Services Canada LP Pension Plan (the "Plan") is maintained solely for certain eligible legacy Partnership participants. The Plan is a defined benefit pension plan that allows for employee contributions. We expect to contribute $0.2 million to the pension plan in 2018.

(in millions of U.S. dollars, except per-share amounts)

The net annual periodic pension cost related to the pension plan for the years ended December 31, 2017, 2016 and 2015 includes the following components:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Service cost benefits earned | $ 0.5 | $ 0.7 | $ 0.9 |
| Interest cost on benefit obligation | 0.6 | 0.7 | 0.7 |
| Expected return on plan assets | (0.9) | (0.9) | (0.9) |
| Net period benefit cost | $ 0.2 | $ 0.5 | $ 0.7 |

A comparison of the pension benefit obligation and related plan assets for the pension plan at December 31 is as follows:

| | 2017 | 2016 |
|---|---|---|
| Benefit obligation at January 1 | $ (17.4) | $ (15.1) |
| Service cost | (0.5) | (0.7) |
| Interest cost | (0.6) | (0.7) |
| Actuarial (gain) loss | (0.9) | (0.5) |
| Employee contributions | (0.1) | (0.1) |
| Benefits paid | 0.2 | 0.1 |
| Settlements | 4.5 | — |
| Foreign currency translation adjustment | (1.0) | (0.4) |
| Benefit obligation at December 31 | (15.8) | (17.4) |
| Fair value of plan assets at January 1 | $ 16.1 | $ 14.4 |
| Actual return on plan assets | 1.1 | 0.7 |
| Employer contributions | 1.3 | 0.5 |
| Employee contributions | 0.1 | 0.1 |
| Benefits paid | (0.2) | (0.1) |
| Settlements | (5.4) | — |
| Foreign currency translation adjustment | 0.9 | 0.5 |
| Fair value of plan assets at December 31 | 13.9 | 16.1 |
| Funded status at December 31-excess of obligation over assets | $ (1.9) | $ (1.3) |

Amounts recognized in the balance sheet at December 31 were as follows:

| | 2017 | 2016 |
|---|---|---|
| Non-current liabilities | $ 1.9 | $ 1.3 |

Amounts recognized in accumulated OCL that have not yet been recognized as components of net periodic benefit cost were as follows, net of tax:

| | 2017 | 2016 |
|---|---|---|
| Unrecognized loss | $ 1.6 | $ 0.5 |

We estimate that there will be no amortization of net loss for the pension plan from accumulated OCI to net periodic cost over the next fiscal year.

**(in millions of U.S. dollars, except per-share amounts)**

The following table presents the balances of significant components of the pension plan:

| | 2017 | 2016 |
|---|---|---|
| Projected benefit obligation | $ 15.8 | $ 17.4 |
| Accumulated benefit obligation | 14.4 | 15.1 |
| Fair value of plan assets | 13.9 | 16.1 |

The market-related value of the pension plan's assets is the fair value of the assets. Plan assets are invested in a common collective trust which totaled $13.9 million and $16.1 million for the years ended December 31, 2017 and 2016, respectively.

We determine the level in the fair value hierarchy within which the fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the common/collective trust is valued at a fair value which is equal to the sum of the market value of the fund's investments, and is categorized as Level 2. There are no investments categorized as Level 1 or 3.

The following table presents the significant assumptions used to calculate our benefit obligations:

| | 2017 | 2016 |
|---|---|---|
| **Weighted-Average Assumptions** | | |
| Discount rate | 3.5 % | 4.0 % |
| Rate of compensation increase | 2.0 % | 2.0 % |

The following table presents the significant assumptions used to calculate our benefit expense:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Weighted-Average Assumptions** | | | |
| Discount rate | 4.0 % | 4.3 % | 4.0 % |
| Rate of return on plan assets | 5.8 % | 5.8 % | 6.0 % |
| Rate of compensation increase | 2.0 % | 3.0 % | 4.0 % |

We use December 31 as the measurement date for the Plan, and we set the discount rate assumptions on an annual basis on the measurement date. This rate is determined by management based on information agreed with our actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of the year ended December 31, 2017, 2016 and 2015, were based on the CIA / Natcan curve, which was designed by the Canadian Institute of Actuaries and Natcan Investment Management to provide a means for sponsors of Canadian plans to value the liabilities of their postretirement benefit plans. The CIA / Natcan curve is a hypothetical yield curve represented by extrapolating the corporate AA-rated yield curve beyond 10 years using yields on provincial AA bonds with a spread added to the provincial AA yields to approximate the difference between corporate AA and provincial AA credit risk. The CIA / Natcan curve utilizes this approach because there are very few corporate bonds rated AA or above with maturities of 10 years or more in Canada.

We employ a balanced total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, and the plan's funded status. Plan assets in the common collective trust are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across Canadian, U.S. and other international equities, as well as among growth, value and small and large capitalization stocks.

(in millions of U.S. dollars, except per-share amounts)

The pension plan assets weighted average allocations in the common collective trust were as follows:

| | 2017 | 2016 |
|---|---|---|
| Canadian equity | 30 % | 30 % |
| U.S. equity | 14 % | 14 % |
| International equity | 14 % | 14 % |
| Canadian fixed income | 39 % | 39 % |
| International fixed income | 3 % | 3 % |
| | 100 % | 100 % |

Our expected future benefit payments for each of the next five years and in the aggregate for the five years thereafter, are as follows in Cdn$:

| | 2017 |
|---|---|
| 2018 | Cdn$ 0.4 |
| 2019 | 0.4 |
| 2020 | 0.5 |
| 2021 | 0.5 |
| 2022 | 0.6 |
| 2023-2027 | 4.0 |

***Defined Contribution Plans***

We maintain a 401(k) retirement savings plan, registered retirement savings plan, and another defined contribution plan for the benefit of our eligible employees. Substantially all of our employees who meet certain service and age requirements are eligible to participate in these plans. Our plan documents provide that any matching contributions by us are discretionary. We have made or accrued matching contributions to these plans of $1.2 million, $1.4 million, and $1.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

## 18. Common shares

### Stock Repurchase Program

On December 29, 2016, we commenced an NCIB for each series of our convertible unsecured subordinated debentures, our common shares and for each series of the preferred shares of APPEL, our wholly-owned subsidiary. The Board authorization permitted the Company to repurchase stock through open market repurchases. The NCIB expired on December 28, 2017. For the year ended December 31, 2017, we repurchased a cumulative 0.1 million common shares at a total cost of $0.2 million. Repurchases and retirement of common shares are recorded to common shares on the consolidated balance sheets.

On December 29, 2017, we commenced a new NCIB for our Series C and Series D Debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd. (“APPEL”), our wholly-owned subsidiary. The new NCIBs expire on December 28, 2018 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the new NCIBs. Under the new NCIBs, we may purchase up to a total of 11,308,946 common shares based on 10% of our public float as of December 15, 2017 and we are limited to daily purchases of 11,789 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the new NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the New York Stock Exchange in compliance with rule 10b-18 under the U.S. Securities Exchange Act of 1934, as amended, or other designated exchanges and published marketplaces in the U.S. in accordance with applicable regulatory requirements. The ability to make certain purchases through the facilities of the NYSE is subject to regulatory approval.

**Common Share Dividends**

We paid dividends of Cdn$0.03 per outstanding share to our common stockholders during the first, second, third and fourth quarters of 2015.

On February 9, 2016, we announced the elimination of our common stock dividend, effective immediately. In conjunction with the elimination of the common stock dividend, our dividend reinvestment plan (the “Plan”) also was eliminated. We filed a post-effective amendment to our registration statement on Form S-3 (Registration No. 333-194204) to deregister all of the Company’s common shares that remain unissued under the Plan.

**19. Preferred shares issued by a subsidiary company**

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the “Series 1 Shares”) priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. Beginning on June 30, 2012, the Series 1 Shares were redeemable by the subsidiary company at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the “Series 2 Shares”) priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate was reset on December 31, 2014 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares were and will be redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares had and will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the” Series 3 Shares”) of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%. On December 31, 2014, 1,661,906 of Series 2 shares were converted to Series 3 shares.

The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of the subsidiary company. If, and for so long as, the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

The Series 1, 2 and 3 Shares are accounted for as a non-controlling interest on our consolidated balance sheets and consolidated statements of operations. The subsidiary company paid aggregate dividends of $8.6 million, $8.5 million and $8.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. In 2017, we repurchased and cancelled 250,000 of the Series 1 Shares at Cdn$15.50 per share for $3.1 million and recorded a $3.0 million loss as a component of income attributable to preferred shares of a subsidiary company in the year ended December 31, 2017.

(in millions of U.S. dollars, except per-share amounts)

## 20. Basic and diluted loss per share

Basic loss per share is calculated by dividing net loss by the weighted average common shares outstanding during their respective period. Diluted earnings per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the years ended December 31, 2017, 2016 and 2015, diluted loss per share is equal to basic loss per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2017, 2016 and 2015:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Numerator:** | | | |
| Loss from continuing operations attributable to Atlantic Power Corporation | $ (98.6) | $ (122.4) | $ (92.9) |
| Income (loss) from discontinued operations, net of tax | — | — | 30.5 |
| Net loss attributable to Atlantic Power Corporation | $ (98.6) | $ (122.4) | $ (62.4) |
| **Denominator:** | | | |
| Weighted average basic shares outstanding | 115.1 | 119.5 | 121.9 |
| Dilutive potential shares: | | | |
| Convertible debentures | 8.1 | 13.1 | 22.7 |
| LTIP notional units | — | 0.1 | 0.2 |
| Potentially dilutive shares | 123.2 | 132.7 | 144.8 |
| Diluted loss per share from continuing operations attributable to Atlantic Power Corporation [1] | $ (0.86) | $ (1.02) | $ (0.76) |
| Diluted earnings (loss) per share from discontinued operations | — | — | 0.25 |
| | | | |
| Basic and diluted loss per share attributable to Atlantic Power Corporation | $ (0.86) | $ (1.02) | $ (0.51) |

(1) The dilutive effect of our convertible debentures is calculated using the “if-converted method.” Under the if-converted method, the debentures are assumed to be converted at the beginning of the period, and the resulting common shares are included in the denominator of the diluted EPS calculation for the entire period being presented. Interest expense, net of any income tax effects, would be added back to the numerator for purposes of the if-converted calculation. Potentially dilutive shares from convertible debentures and notional units have been excluded from fully diluted shares for the years ended December 31, 2017, 2016 and 2015, respectively, because their impact would be anti-dilutive.

## 21. Discontinued operations

On June 26, 2015, APT, our wholly-owned, direct subsidiary, sold our Wind Projects under a definitive agreement (the “Purchase Agreement”) with TerraForm AP Acquisition Holdings, LLC (“TerraForm”), an affiliate of SunEdison, Inc. (an affiliate of TerraForm Power, Inc.). The sale was completed for aggregate cash proceeds of approximately $335 million after transaction fees, exclusive of transaction-related taxes. We recorded an approximate $46.8 million gain on sale, which is included as a component of income from discontinued operations in the consolidated statements of operations for the year ended December 31, 2015.

(in millions of U.S. dollars, except per-share amounts)

Terraform acquired from APT, 100% of APT's direct membership interests in a holding company formed to facilitate the sale, thereby acquiring our indirect interests in our portfolio of Wind Projects consisting of five operating wind projects in Idaho and Oklahoma and representing 521 MW net ownership: Goshen (12.5% economic interest), Idaho Wind (27.6% economic interest), Meadow Creek (100% economic interest); Rockland Wind Farm (50% economic interest, but consolidated on a 100% basis); and Canadian Hills (99% economic interest). As a result of the sale, we deconsolidated approximately $249 million of project debt (or approximately $274 million as adjusted for our proportional ownership of Rockland, Goshen North and Idaho Wind) and approximately $224 million of non-controlling interest related to tax equity interests at Canadian Hills and the minority ownership interests at Rockland and Canadian Hills.

The Wind Projects were designated as assets held for sale and discontinued operations on March 31, 2015, the date we established a firm commitment to a plan to sell the wind assets. Our determination to designate the Wind Projects as discontinued operations was based on the impact the sale would have on our operations and financial results and because the Wind Projects made up the entirety of our Wind reportable segment. We stopped depreciating the property, plant and equipment of the Wind Projects on the designation date.

The following tables summarize the revenue, loss from operations, and income tax expense of the Wind Projects for the years ended December 31, 2015:

| | 2015 |
|---|---|
| Revenue | $ 34.8 |
| Project expenses: | |
| Operations and maintenance | 10.8 |
| Depreciation and amortization | 10.3 |
| | 21.1 |
| Project other income (expense): | |
| Change in fair value of derivatives | (0.7) |
| Equity in earnings of unconsolidated affiliates | (0.5) |
| Interest expense, net | (6.7) |
| Gain on sale of asset | 46.8 |
| | 38.9 |
| Income from operations of discontinued businesses | 52.6 |
| Income tax expense | 33.1 |
| Income from operations of discontinued businesses, net of tax | 19.5 |
| Net loss attributable to noncontrolling interests of discontinued businesses | (11.0) |
| Income from operations of discontinued businesses, net of noncontrolling interests | $ 30.5 |

The following table summarizes the operating and investing cash flows of the Wind Projects for the years ended December 31, 2015:

| | December 31, 2015 |
|---|---|
| Cash provided by operating activities | $ 21.9 |
| Cash used in investing activities | (12.8) |

Basic and diluted loss per share related to income (loss) from discontinued operations for the Wind Projects was $0.25 for the years ended December 31, 2015.

(in millions of U.S. dollars, except per-share amounts)

## 22. Segment and geographic information

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as a result of significant project asset sales and in order to align our reportable business segments with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. 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. We use Project Adjusted EBITDA to provide comparative information about segment performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented on a proportionally consolidated basis in Project Adjusted EBITDA and in the reconciliation of Project Adjusted EBITDA to project income (loss). The Wind Projects, which were components of the former Wind segment are excluded in the income (loss) from continuing operations line item in the table below.

A reconciliation of Project Adjusted EBITDA to net income (loss) from continuing operations to is included in the tables below:

| | East U.S. | West U.S. | Canada | Un-Allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year Ended December 31, 2017** | | | | | |
| Project revenues | $ 152.5 | $ 108.9 | $ 168.6 | $ 1.0 | $ 431.0 |
| Segment assets | 632.4 | 189.9 | 239.6 | 96.9 | 1,158.8 |
| Goodwill | 17.7 | — | 3.6 | — | 21.3 |
| Capital expenditures | 4.6 | 0.1 | 0.8 | — | 5.5 |
| Project Adjusted EBITDA | $ 112.5 | $ 49.1 | $ 125.8 | $ 1.4 | $ 288.8 |
| Change in fair value of derivative instruments | (6.3) | — | 6.1 | (1.9) | (2.1) |
| Depreciation and amortization | 45.2 | 35.5 | 51.9 | 0.6 | 133.2 |
| Interest, net | 19.2 | — | — | — | 19.2 |
| Impairment | 72.4 | 85.6 | 29.1 | — | 187.1 |
| Other project income | (1.0) | — | (0.1) | (0.1) | (1.2) |
| Project (loss) income | (17.0) | (72.0) | 38.8 | 2.8 | (47.4) |
| Administration | — | — | — | 23.6 | 23.6 |
| Interest expense, net | — | — | — | 64.2 | 64.2 |
| Foreign exchange loss | — | — | — | 16.3 | 16.3 |
| Other expense, net | — | — | — | (0.4) | (0.4) |
| Net (loss) income before income taxes | (17.0) | (72.0) | 38.8 | (100.9) | (151.1) |
| Income tax benefit | — | — | — | (58.1) | (58.1) |
| Net (loss) income | $ (17.0) | $ (72.0) | $ 38.8 | $ (42.8) | $ (93.0) |

**(in millions of U.S. dollars, except per-share amounts)**

| | East U.S. | West U.S. | Canada | Un-Allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year Ended December 31, 2016** | | | | | |
| Project revenues | $ 134.5 | $ 101.3 | $ 162.5 | $ 0.9 | $ 399.2 |
| Segment assets | 754.2 | 313.6 | 291.8 | 97.2 | 1,456.8 |
| Goodwill | 32.4 | — | 3.6 | — | 36.0 |
| Capital expenditures | 6.2 | — | 0.9 | 0.1 | 7.2 |
| Project Adjusted EBITDA | $ 92.4 | $ 51.2 | $ 58.8 | $ (0.2) | $ 202.2 |
| Change in fair value of derivative instruments | (9.2) | — | (25.5) | (3.2) | (37.9) |
| Depreciation and amortization | 44.1 | 39.4 | 49.5 | 0.5 | 133.5 |
| Interest, net | 10.9 | — | — | — | 10.9 |
| Impairment | 15.4 | — | 70.5 | — | 85.9 |
| Other project income | — | — | — | (0.3) | (0.3) |
| Project income (loss) | 31.2 | 11.8 | (35.7) | 2.8 | 10.1 |
| Administration | — | — | — | 22.6 | 22.6 |
| Interest expense, net | — | — | — | 106.0 | 106.0 |
| Foreign exchange loss | — | — | — | 13.9 | 13.9 |
| Other income, net | — | — | — | (3.9) | (3.9) |
| Net income (loss) before income taxes | 31.2 | 11.8 | (35.7) | (135.8) | $ (128.5) |
| Income tax benefit | — | — | — | (14.6) | (14.6) |
| Net income (loss) | $ 31.2 | $ 11.8 | $ (35.7) | $ (121.2) | $ (113.9) |

| | East U.S. | West U.S. | Canada | Un-Allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year Ended December 31, 2015** | | | | | |
| Project revenues | $ 150.0 | $ 104.6 | $ 164.7 | $ 0.9 | $ 420.2 |
| Segment assets | 819.9 | 228.6 | 423.8 | 198.9 | 1,671.2 |
| Goodwill | 47.8 | — | 86.7 | — | 134.5 |
| Capital expenditures | 7.0 | 0.5 | 3.4 | 0.4 | 11.3 |
| Project Adjusted EBITDA | $ 104.8 | $ 46.9 | $ 59.7 | $ (2.5) | $ 208.9 |
| Change in fair value of derivative instruments | — | — | (16.0) | 0.6 | (15.4) |
| Depreciation and amortization | 42.5 | 39.3 | 47.2 | 1.1 | 130.1 |
| Interest, net | 9.8 | — | — | — | 9.8 |
| Impairment | 13.7 | — | 114.1 | — | 127.8 |
| Other project expense | 0.1 | — | 0.1 | (2.2) | (2.0) |
| Project income (loss) | 38.7 | $ 7.6 | $ (85.7) | $ (2.0) | (41.4) |
| Administration | — | — | — | 29.4 | 29.4 |
| Interest, net | — | — | — | 107.1 | 107.1 |
| Foreign exchange gain | — | — | — | (60.3) | (60.3) |
| Other income, net | — | — | — | (3.1) | (3.1) |
| Income (loss) from continuing operations before income taxes | 38.7 | 7.6 | (85.7) | (75.1) | (114.5) |
| Income tax benefit | — | — | — | (30.4) | (30.4) |
| Net income (loss) from continuing operations | $ 38.7 | $ 7.6 | $ (85.7) | $ (44.7) | $ (84.1) |

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2017, 2016 and 2015 and Property, Plant & Equipment as of December 31, 2016 and 2015, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

(in millions of U.S. dollars, except per-share amounts)

| | Revenue | | | Property, Plant and Equipment, net of accumulated depreciation | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2017 | 2016 |
| United States | $ 262.4 | $ 236.7 | $ 255.5 | $ 426.2 | $ 499.2 |
| Canada | 168.6 | 162.5 | 164.7 | 176.1 | 234.0 |
| Total | $ 431.0 | $ 399.2 | $ 420.2 | $ 602.3 | $ 733.2 |

IESO, Niagara Mohawk, San Diego Gas & Electric and BC Hydro provided 20.3%, 10.7%, 10.6% and 10.3%, respectively, of total consolidated revenues for the year ended December 31, 2017. OEFC, San Diego Gas & Electric, and BC Hydro provided 29.2%, 11.5%, and 10.9%, respectively, of total consolidated revenues for the year ended December 31, 2016. OEFC, San Diego Gas & Electric, and BC Hydro provided 29.2%, 11.0%, and 10.0%, respectively, of total consolidated revenues for the year ended December 31, 2015. IESO and OEFC purchase electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the Canada segment, respectively. San Diego Gas & Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West U.S. segment, Niagara Mohawk purchases electricity from the Curtis Palmer project in the East U.S. segment, and BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Canada segment.

## 23. Commitments and contingencies

***Commitments***

***Operating Lease Commitments***

We lease our office properties and equipment under operating leases expiring on various dates through 2022. Certain operating lease agreements over their lease term include provisions for scheduled rent increases. We recognize the effects of these scheduled rent increases on a straight-line basis over the lease term. We also have leased office properties for which we have entered into sub-lease agreements with tenants. The table below excludes leased properties where the net rent expense results in rental income for the company. Lease expense under operating leases was $0.5 million, $0.6 million and $1.5 million for the years ended December 31, 2017, 2016, and 2015, respectively. Future minimum lease commitments under operating leases for the years ending after December 31, 2017, are as follows:

| | |
|---|---|
| 2018 | $ 0.5 |
| 2019 | 0.2 |
| 2020 | 0.1 |
| 2021 | — |
| 2022 | — |
| Thereafter | — |
| | $ 0.8 |

(in millions of U.S. dollars, except per-share amounts)

***Management Service Commitments***

Our Manchief project is operated by a third party under a contract that expires in April 2022. As of December 31, 2017, our commitments under this agreement is estimated as follows:

| | |
|---|---|
| 2018 | $ 0.4 |
| 2019 | 0.4 |
| 2020 | 0.4 |
| 2021 | 0.4 |
| 2022 | 0.1 |
| Thereafter | — |
| | $ 1.7 |

***Fuel Supply and Transportation Commitments***

We have entered into long-term contractual arrangements to procure fuel and transportation services for our projects. The commitments listed below include only contracts for fuel contracts that are not reimbursed or passed through under the terms of the relevant PPAs. As of December 31, 2017, our commitments under such outstanding agreements are estimated as follows:

| | |
|---|---|
| 2018 | $ 3.9 |
| 2019 | 13.5 |
| 2020 | 11.6 |
| 2021 | 11.5 |
| 2022 | 22.9 |
| Thereafter | 22.9 |
| | $ 86.3 |

***Guarantees***

We and our subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint venture agreements, operation and maintenance agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

***Contingencies***

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of December 31, 2017.

(in millions of U.S. dollars, except per-share amounts)

## 24. Unaudited selected quarterly financial data

Unaudited selected quarterly financial data are as follows:

| | Quarter Ended 2017 | | | | |
|---|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, | Total |
| Project revenue | $ 100.0 | $ 108.6 | $ 124.0 | $ 98.4 | $ 431.0 |
| Project (loss) income | (39.7) | (20.9) | (12.1) | 25.3 | (47.4) |
| Net loss | (38.9) | (33.7) | (19.8) | (0.6) | (93.0) |
| Net loss attributable to Atlantic Power Corporation | (41.1) | (32.9) | (21.9) | (2.7) | (98.6) |
| | | | | | |
| Loss per share attributable to Atlantic Power Corporation | $ (0.36) | $ (0.29) | $ (0.19) | $ (0.02) | $ (0.86) |
| Weighted average number of common shares outstanding-basic | 115.2 | 115.3 | 115.2 | 114.8 | 115.1 |
| Diluted loss per share attributable to Atlantic Power Corporation | $ (0.36) | $ (0.29) | $ (0.19) | $ (0.02) | $ (0.86) |
| Weighted average number of common shares outstanding-diluted[1] | 115.2 | 115.3 | 115.2 | 114.8 | 115.1 |

| | Quarter Ended 2016 | | | | |
|---|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, | Total |
| Project revenue | $ 93.4 | $ 101.2 | $ 98.2 | $ 106.4 | $ 399.2 |
| Project income (loss) | 13.3 | (57.1) | 25.2 | 28.7 | 10.1 |
| Net loss | (4.4) | (80.3) | (16.3) | (12.9) | (113.9) |
| Net loss attributable to Atlantic Power Corporation | (6.6) | (82.4) | (18.5) | (14.9) | (122.4) |
| | | | | | |
| Loss per share attributable to Atlantic Power Corporation | $ (0.06) | $ (0.69) | $ (0.15) | $ (0.12) | $ (1.02) |
| Weighted average number of common shares outstanding-basic | 115.5 | 119.3 | 121.6 | 121.9 | 119.5 |
| Diluted loss per share attributable to Atlantic Power Corporation | $ (0.06) | $ (0.69) | $ (0.15) | $ (0.12) | $ (1.02) |
| Weighted average number of common shares outstanding-diluted[1] | 115.5 | 119.3 | 121.6 | 121.9 | 119.5 |

(1) The calculation excludes potentially dilutive shares from convertible debentures and LTIP notional units because their impact would be anti-dilutive.

**ATLANTIC POWER CORPORATION**

**SCHEDULE I—CONDENSED BALANCE SHEETS (PARENT COMPANY ONLY)**

**(in millions of U.S. dollars)**

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 41.8 | $ 49.2 |
| Prepayments and other current assets | 1.8 | 2.3 |
| Total current assets | 43.6 | 51.5 |
| Investment in and advances to / from subsidiaries | 46.6 | 116.1 |
| Total assets | $ 90.2 | $ 167.6 |
| **Liabilities** | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $ 1.7 | $ 1.5 |
| Total current liabilities | 1.7 | 1.5 |
| Convertible debentures | 105.5 | 100.4 |
| Other long-term liabilities | 1.3 | 1.1 |
| Total liabilities | 108.5 | 103.0 |
| Shareholders' equity | (18.3) | 64.6 |
| Total liabilities and shareholders' equity | $ 90.2 | $ 167.6 |

See accompanying notes to condensed financial statements.

**ATLANTIC POWER CORPORATION**

**SCHEDULE I—CONDENSED STATEMENTS OF OPERATIONS (PARENT COMPANY ONLY)**

**(in millions of U.S. dollars)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Administrative and other expenses: | | | |
| Administrative expense | $ 5.4 | $ 5.9 | $ 6.3 |
| Interest expense, net | 11.6 | 7.3 | 25.6 |
| Foreign exchange loss (gain) | 4.0 | 10.6 | (33.0) |
| Other expense (income) | 0.2 | (3.6) | (2.6) |
| (Loss) income from parent company | (21.2) | (20.2) | 3.7 |
| Equity losses of subsidiaries, net of income tax benefit | (71.8) | (93.7) | (87.8) |
| Net loss from continuing operations | (93.0) | (113.9) | (84.1) |
| Net income from discontinued operations, net of tax | — | — | 19.5 |
| Net loss | $ (93.0) | $ (113.9) | $ (64.6) |

See accompanying notes to condensed financial statements.

**ATLANTIC POWER CORPORATION**

**SCHEDULE I—CONDENSED STATEMENTS OF CASH FLOWS (PARENT COMPANY ONLY)**

**(in millions of U.S. dollars)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Cash provided by operating activities: | | | |
| Net loss | $ (93.0) | $ (113.9) | $ (64.6) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | | |
| Non-cash losses from subsidiaries, net of taxes | 71.8 | 93.7 | 87.8 |
| Dividends received from subsidiaries | 67.9 | 33.6 | 32.5 |
| Unrealized foreign exchange loss (gain) | 4.0 | 10.6 | (33.0) |
| Gain on purchase and cancellation of convertible debentures | — | (4.7) | (3.1) |
| Change in other operating balances | | | |
| Accounts receivable | (1.1) | 11.5 | (14.9) |
| Prepayments and other assets | 1.4 | 6.0 | 13.3 |
| Accounts payable and accrued liabilities | 0.5 | (1.1) | (23.4) |
| Cash provided by (used in) operating activities | 51.5 | 35.7 | (5.4) |
| Cash (used in) provided by investing activities: | | | |
| Advances to / from and investments in subsidiaries | (57.8) | 216.7 | 330.4 |
| Cash (used in) provided by investing activities | (57.8) | 216.7 | 330.4 |
| Cash used in financing activities: | | | |
| Common share repurchases | (0.2) | (19.5) | — |
| Dividends paid to common shareholders | — | — | (11.1) |
| Repayment of convertible debentures | — | (187.5) | (18.9) |
| Payments received from intercompany note | — | 1.5 | 29.6 |
| Repayment of intercompany note | (0.9) | (9.2) | — |
| Repayment of long-term debt | — | — | (319.9) |
| Cash used in financing activities | (1.1) | (214.7) | (320.3) |
| Net (decrease) increase in cash and cash equivalents | (7.4) | 37.7 | 4.7 |
| Cash and cash equivalents at beginning of period | 49.2 | 11.5 | 6.8 |
| Cash and cash equivalents at end of period | $ 41.8 | $ 49.2 | $ 11.5 |
| Supplemental cash flow information | | | |
| Interest paid | $ 6.2 | $ 48.3 | $ 51.1 |

See accompanying notes to condensed financial statements

## ATLANTIC POWER CORPORATION

## SCHEDULE I—NOTES TO CONDENSED FINANCIAL STATEMENTS (PARENT COMPANY ONLY)

**(in millions of U.S. dollars)**

### 1. Nature of business

Atlantic Power Corporation (the "Parent Company") is a holding company that conducts substantially all of its business through its subsidiaries. As specified in certain of its subsidiaries' credit agreements, there are restrictions on the Parent Company's ability to obtain funds from certain of its subsidiaries through dividends (refer to Note 11, "Long-term debt", to the consolidated financial statements). As of December 31, 2017, total Atlantic Power Corporation shareholders' equity was $18.4 million in deficit and approximately $16.3 million of net assets at certain subsidiaries constituted restricted net assets as defined in Rule 4-08(e)(3) of Regulation S-X. The restricted net assets of these subsidiaries exceeded 25% of our consolidated net assets, thus requiring this Schedule I, "Condensed Financial Information of the Registrant." Accordingly, the balance sheets as of December 31, 2017 and 2016, and the statements of operations and cash flows for the years ended December 31, 2017, 2016 and 2015, have been presented on a "Parent-only" basis. In these statements, the Parent Company's investments in its consolidated subsidiaries are presented under the equity method of accounting. We had no undistributed earnings from our unconsolidated investments for the years ended December 31, 2017, 2016 and 2015, respectively.

As disclosed in Note 11, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the term loan that declines quarterly based on a predetermined specified schedule. APLP Holdings has made principal payments to meet the targeted debt balance requirement as of December 31, 2017 and is not prohibited from making dividends to the Parent Company. The consolidated equity of APLP Holdings was approximately $54.7 million at December 31, 2017 and includes the subsidiaries with restricted net assets of $16.3 million at December 31, 2017 disclosed above.

The Parent-only financial statements should be read in conjunction with our consolidated financial statements included elsewhere herein.

### 2. Dividends received

The Parent Company received dividends of $67.9 million, $33.6 million and $32.5 million in 2017, 2016 and 2015, respectively, from its consolidated and unconsolidated subsidiaries.

**ATLANTIC POWER CORPORATION**

**SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS**

**FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 and 2015**

**(in millions of U.S. dollars)**

| | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| **Income tax valuation allowance, deducted from deferred tax assets:** | | | | | |
| Year ended December 31, 2017 | $ 186.0 | $ (34.6) | $ — | $ — | $ 151.4 |
| Year ended December 31, 2016 | 175.2 | 10.8 | — | — | 186.0 |
| Year ended December 31, 2015 | 168.6 | 6.6 | — | — | 175.2 |

## CORPORATE INFORMATION

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**Annual Meeting**
The Annual Meeting of Shareholders will be held on June 19, 2018.

**Stock Exchange Information**
TSX Ticker Symbol: ATP
NYSE Ticker Symbol: AT

**Investor Information**
Individual shareholders, security analysts, portfolio managers and other institutional investors seeking information about the company should contact Atlantic Power Corporation Investor Relations at 617.977.2700 or by email at info@atlanticpower.com.

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