INNERGEX

INNERGEX RENEWABLE ENERGY INC.

ANNUAL REPORT

AT DECEMBER 31, 2017

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Innergex Renewable Energy Inc. is a leading Canadian independent renewable power producer. Active since 1990, the Corporation develops, acquires, owns and operates run-of-river hydroelectric facilities, wind farms, solar photovoltaic farms and geothermal power facilities and carries out its operations in Canada, in the United States, in France and in Iceland. The Corporation's shares are listed on the Toronto Stock Exchange under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures are listed under the symbol INE.DB.A.

Innergex's mission is to increase its production of renewable energy by developing and operating high-quality facilities while respecting the environment and balancing the best interests of the host communities, its partners and its investors.

2017 Highlights

- Production up 25% over 2016
- Revenues up 37% over 2016
- Adjusted EBITDA[1] up 38% over 2016
- Acquisition of six wind farms in France with Desjardins Group Pension Plan
- Two hydro facilities in British Columbia reached commercial operation
- Arrangement agreement pursuant to which Innergex is to acquire all of the issued and outstanding common shares of Alterra Power Corp. The transaction closed on February 6, 2018

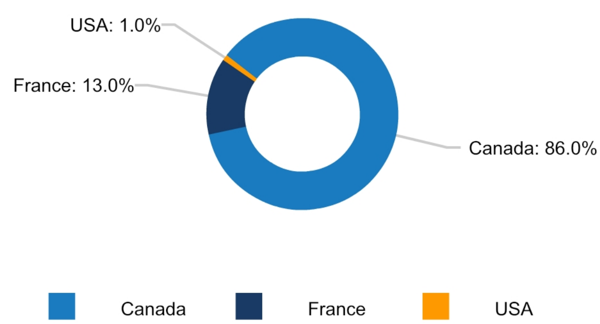
1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of the Management's Discussion and Analysis for more information.

Installed Capacity[1]

	Gross	Net[2]
Hydro	1,029	684
Wind	1,429	671
Solar	54	53
Geothermal	174	94
TOTAL	**2,686**	**1,502**

[1] Installed capacity is the installed capacity for all operating facilities as at February 21, 2018.
[2] Net capacity is the proportional share of the total capacity attributable to Innergex based on its ownership interest in each facility.

2017 Revenues by country

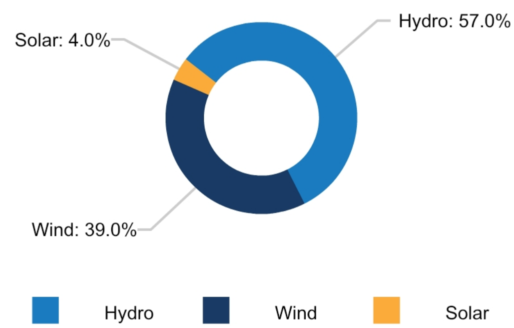


Facilities[1]

	In operations	In development
Hydro	34	1
Wind	24	1
Solar	3	—
Geothermal	2	—
TOTAL	**63**	**2**

[1] Number of facilities as at February 21, 2018.

2017 Revenues by energy source

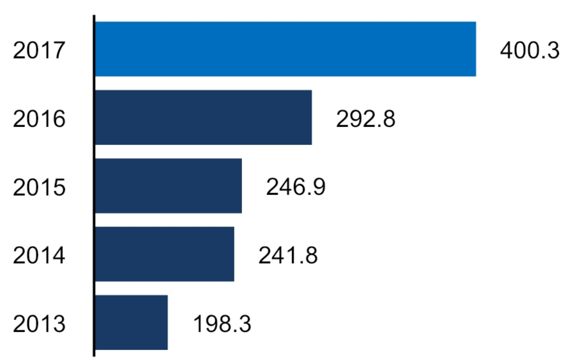


FINANCIAL HIGHLIGHTS

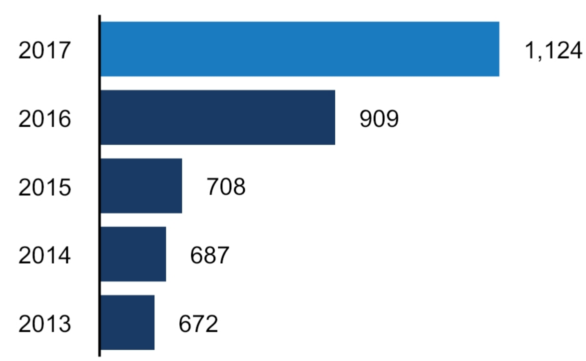
	Year ended December 31		
	2017	2016	2015
OPERATING RESULTS			
Production (MWh)	4,394,210	3,521,645	2,987,637
Revenues	400,263	292,785	246,869
Adjusted EBITDA[1]	298,728	215,983	183,738
Adjusted EBITDA Margin (%)[1]	75%	74%	74%
Adjusted EBITDA Proportionate[1]	308,343	224,368	193,179
Net Earnings (Loss)	19,668	32,043	(48,383)
Adjusted Net Earnings[1]	16,194	29,076	19,731
Cash Flow from Operating Activities	192,451	76,753	4,557
Free Cash Flow[1]	87,207	75,702	74,386
Payout Ratio (%)[1]	82%	91%	86%
COMMON SHARES			
Dividends	71,621	68,524	63,646
Weighted average number of common shares (in 000s)	108,427	106,883	102,304
FINANCIAL POSITION			
Total Assets	4,190,456	3,604,204	3,128,303
Non-current liabilities	3,493,423	2,898,602	2,471,576
Non-controlling interests	14,920	14,712	21,907
Equity attributable to owners	435,269	470,520	449,650

1. Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted EBITDA Proportionate, Adjusted Net Earnings, Free Cash Flow and Payout ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of the Management's Discussion and Analysis for more information.

Revenues (in millions of $)



Net Installed Capacity (MW)



MESSAGE TO SHAREHOLDERS

THINK BIG, AIM TRUE

With its recently commissioned facilities and new acquisitions, Innergex has expanded its net installed capacity by 63% since December 31, 2016. Now with 2,686 gross MW in operation (1,502 net MW[1]), Innergex can take pride in not only being a leader in Canada but the largest independent producer of renewable energy in British Columbia.

Since 1990, Innergex has focused exclusively on producing renewable energy. We knew at that time that renewable energy was essential for the well-being of our planet. Now, 27 years later, our focus remains the same, and it continues to be the guiding factor in everything we do every day. What's more, we are proud of the part we play in helping the global energy transition.

Over the last few years, we have successfully completed a number of major projects in Canada, including several in British Columbia where we commissioned four hydroelectric facilities from 2015 to 2017: Tretheway Creek (21.2 MW), Big Silver Creek (40.6 MW), Upper Lillooet River (81.4 MW) and Boulder Creek (25.3 MW). This most recent commissioning marks the culmination of a period of major construction projects that we undertook simultaneously in Western Canada.

In Quebec, the Mesgi'g Ugju's'n wind project (150 MW) began commercial operation at the end of 2016. This project, developed in partnership with Quebec's three Mi'gmaq communities, is one of a kind. It exemplifies our ability to develop long-term partnerships that create benefits shared with local communities, making a tangible difference for the economic future of their communities.

Every day we work to bring projects to life that meet the expectations and have the support of their host communities. Our development teams have also been hard at work for the last several years on a number of potential projects, some of which could be developed in cooperation with First Nations as well as other partners.

All our enormous successes are the result of several years of dedication by our talented team. Each individual team member is committed to the company's values and is prepared to go all out to achieve a common goal. It is because of our employees that we are able to successfully establish such strong and long-lasting relationships with our partners.

Now that we have completed our construction activities in Canada, we can focus even more on growth opportunities to be seized throughout the country and internationally. As a leader in renewable energy production in Canada, we are always on the lookout for new project opportunities with the goal of establishing facilities in other provinces. At the moment, we are excited to have pre-qualified to participate in the request for proposals for up to 200 MW of wind power in Saskatchewan.

GO THE EXTRA MILE

In 2015, we adopted a five-year strategic plan and continue to implement it successfully. We remain committed to producing energy exclusively from renewable sources and we plan to continue to grow with this strategy in mind. Our plan also consists of diversifying our assets, expanding our operations throughout Canada, and further developing our presence internationally.

Our growth strategy includes a number of target markets such as France, the United States and Latin America. With the valuable help of our team of experts, Innergex acquired 15 wind farms in France in less than two years. These transactions also demonstrated our expertise in project management, as the commissioning of three of these wind farms was completed under our supervision. An essential component to our growth in France lies in the expertise of our team that is now working from our new office in Lyon who are tasked with developing and acquiring new projects. We are very pleased with the results that we have achieved so far. With close to 320 gross MW (221 net MW) in operation, our growth in France is gaining momentum and marks a first step in our global growth strategy.

Our recent acquisition of Alterra Power Corp. ("Alterra") added 840 gross MW (378 net MW) to our installed capacity and helped us achieve the four objectives set in our strategic plan. This $1.1 billion transaction -the largest in Innergex's history- enables us to manage 1,960 gross MW (1,057 net MW) in Canada alone, with new hydroelectric facilities as well as a new wind farm in British Columbia.

1 Net capacity represents the proportional share of the total capacity attributable to Innergex, based on its ownership interest in these facilities and projects. The remaining capacity is attributable to the partners' ownership share.

In addition to these new assets that strengthen our presence in Canada, the Alterra acquisition boosts and reinforces our position in North America with a very attractive platform for growth that already manages 234 gross MW (131 net MW) in the United States. In 2017, we had already made significant strides in the US with the opening of an office in San Diego, California where we have a new team dedicated to seizing growth opportunities. With this acquisition, we can now grow more easily and quickly in the United States. In 2018, we expect to commission the Flat Top wind project (200 MW gross) in Texas. We also intend to begin construction on another wind project also in Texas of the same scale.

The United States represents a market ripe for renewable energy development, and business opportunities there are significant. We firmly intend to carve a niche in this country by developing and acquiring high-quality projects sustained by power purchase agreements or long-term power hedge contracts, whenever possible. With the combined strength and expertise of our team, we are confident that a bright future south of the border awaits us.

Last but not least, the Alterra acquisition in the first quarter of 2018 has enabled us to diversify our offering in terms of power sources by adding geothermal energy to our portfolio. We have also enhanced our geographic presence as our activities now cover Canada, the United States, France and Iceland. And this is just the beginning. We are actively pursuing other growth opportunities, in particular in Latin America where we have initiated work.

ADAPT FOR TOMORROW

The field of renewable energy, like the energy sector in general, is constantly evolving. New processes and technologies are hitting the market and will undoubtedly influence our industry for years to come. Consequently, we always keep our eyes on new trends so that we can stay competitive in our approach and in the development or acquisition of new projects. Renewable energy now encompasses more than pure energy generation and requires collection and storage systems that will help reduce the dependence on changing weather patterns to store the energy produced.

These collection and storage systems help to stabilize energy networks, smooth out production and consumption irregularities, and increase the quality of voltage and other auxiliary systems that can contribute to sound management of the power grid. Soon, they could even become the solution to compete more fiercely with non-renewable sources of energy like coal and other fossil fuels.

Accordingly, we intend to remain at the forefront of our industry and take these new technologies into consideration in our growth plan.

Before concluding, we would like to welcome Ross Beaty to our Board of Directors. He was previously Executive Chairman of Alterra. The growing Innergex family will no doubt benefit from his vast experience in the renewable energy industry.

At Innergex, we are proud of the outstanding work of all of our employees. By working together, with everyone’s different skills, we can achieve a common goal and reach new heights.

On behalf of everyone at Innergex, we want to thank our customers, shareholders, lenders, local communities, suppliers and, of course, all our partners for their confidence and support. Thanks to your collaboration, we see a growing future for the well-being of our communities, our environment and our company.

Jean La Couture
Chairman of the Board of Directors

Michel Letellier
President and Chief Executive Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") is a discussion of the operating results, cash flows and financial position of Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") for the year ended December 31, 2017, and reflects all material events up to February 21, 2018, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the audited consolidated financial statements and the accompanying notes for the year ended December 31, 2017.

The audited consolidated financial statements attached to this MD&A and the accompanying notes for the year ended December 31, 2017, along with the 2016 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). However, some measures referred to in this MD&A are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

All dollar amounts are in thousands of Canadian dollars, except amounts per share or unless otherwise indicated. Some amounts included in this MD&A have been rounded to make reading easier, which may affect some calculations.

To inform readers of the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws ("Forward-Looking Information"). Please refer to the "Forward-Looking Information" section for more information.

Additional information relating to Innergex, including its Annual Information Form, can be found on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at sedar.com or on the Corporation's website at innergex.com. Information contained in or otherwise accessible through our website does not form part of this MD&A and is not incorporated into the MD&A by reference.

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OVERVIEW

The Corporation is a developer, acquirer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind power, solar photovoltaic and geothermal power projects that benefit from low operating and management costs and simple, proven technologies.

Portfolio of Assets

As at the date of this MD&A, the Corporation owns interests in three groups of power-generating projects:

- 63 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1978 and December 2017, the facilities have a weighted average age of approximately 9.0 years. They mostly sell the generated power under long-term Power Purchase Agreements, power hedge contracts or short- and long-term industrial and retail contracts ("PPA") that have a weighted average remaining life of 17.5 years (based on gross long-term average production);

- Two projects scheduled to begin commercial operations in the first quarter of 2018 and in 2020 (the "Development Projects");

- Numerous projects that have secured land rights, for which an investigative permit application has been filed or for which a proposal has been or could be submitted under a Request for Proposal or a Standing Offer Program (collectively the "Prospective Projects"). These projects are at various stages of development.

  Some Prospective Projects are targeted toward specific future Requests for Proposals and other Prospective Projects are maintained or continue to be advance and will be available for future requests for proposals yet to be announced or are targeted toward negotiated PPAs with public utilities or other retail, financial or commercial entities or other various arrangements in Canada or in other countries such as France, the United States and Iceland. Theses numerous Prospective Projects have a combined potential net installed capacity of 8,530 MW (gross 9,200 MW).

  There is no certainty that any Prospective Project will be realized.

The following chart features the Corporation's direct and indirect interests in the Operating Facilities, Development Projects and Prospective Projects.

	63 Operating Facilities	2 Development Projects	Numerous Prospective Projects
HYDRO			
Net	684.3	5.4	1,980.0
Gross	1,028.5	10.0	2,265.0
WIND			
Net	670.7	102.0	6,225.0
Gross	1,429.4	200.0	6,535.0
SOLAR			
Net	53.0	—	85.0
Gross	53.7	—	160.0
GEOTHERMAL			
Net	93.8	—	240.0
Gross	174.0	—	240.0
TOTAL			
Net	**1,501.8**	**107.4**	**8,530.0**
Gross	**2,685.6**	**210.0**	**9,200.0**

(in thousands of Canadian dollars, except as noted and amounts per share)

BUSINESS STRATEGY

The Corporation's strategy for building shareholder value is to develop or acquire high-quality renewable power production facilities that generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital and to distribute a sustainable dividend.

Produce Only Renewable Energy

The Corporation is committed to producing electricity exclusively from renewable energy sources.

Develop Sustainably

In conducting its business, the Corporation strives to achieve a balance between economic, social and environmental considerations and is committed to planning, deciding, managing and operating through the lens of sustainability.

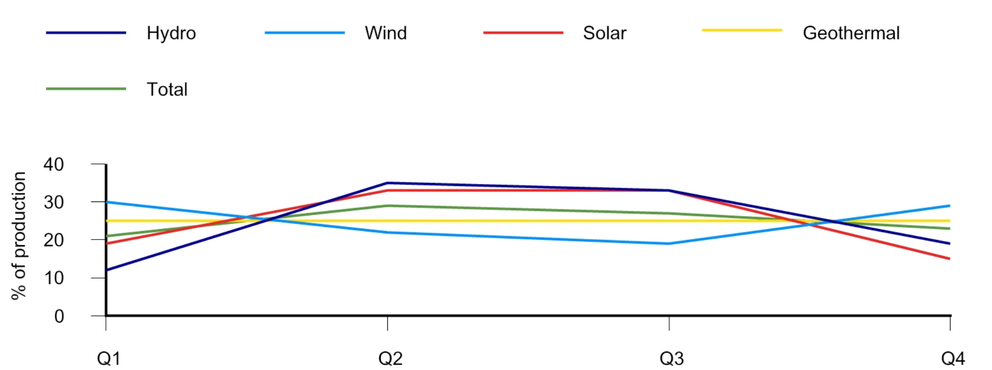
Maintain Diversification of Energy Sources

The Corporation strives to maintain a diversified portfolio of assets in terms of geography and sources of energy to alleviate any seasonal and production variations. The amount of electricity generated by the Operating Facilities is generally dependent on the availability of water flows, wind regimes, solar irradiation and geothermal resources. Lower-than-expected water flows, wind regimes, solar irradiation or geothermal resources in any given year could have an impact on the Corporation's revenues and hence on its profitability. Innergex owns interests in 34 hydroelectric facilities, which draw on 29 watersheds, 24 wind farms, 3 solar farms and 2 geothermal plants, providing significant diversification in terms of operating revenue sources. Furthermore, the nature of hydroelectric, wind, solar and geothermal power generation partially offsets any seasonal variations, as illustrated in the following table:

	Consolidated long-term average production[1]								
In GWh and %	Q1		Q2		Q3		Q4		Total
HYDRO	370	12%	1,066	35%	1,003	33%	581	19%	3,019
WIND	600	30%	429	22%	379	19%	571	29%	1,979
SOLAR	7	19%	12	33%	13	33%	6	15%	38
GEOTHERMAL	320	25%	320	25%	320	25%	320	25%	1,279
Total	1,297	21%	1,827	29%	1,714	27%	1,477	23%	6,315

1. The consolidated long-term average production is the annualized LTA for the facilities in operation at February 21, 2018. The LTA is presented in accordance with revenue recognition accounting rules under IFRS and excludes production from facilities that are accounted for using the equity method, which is presented in the "Investments in Joint Ventures" section.

Seasonality of production by energy source



(in thousands of Canadian dollars, except as noted and amounts per share)

Develop Strategic Relationships

Strategic relationships and partnerships are an important component of the Corporation's business strategy. When the Corporation teams up with a strategic or financial partner, the Corporation and the partner share ownership of the projects concerned.

Pursue Opportunities for Renewable Energy Growth

Growing awareness and concern over issues such as climate change, access to clean energy, energy security, energy efficiency and the environmental impacts of conventional fossil fuels are leading governments around the world to increase their demand for and commitment to the development of renewable energy supply. Consequently, the Corporation believes that the outlook for the renewable energy industry is promising and it therefore intends to pursue growth by developing, acquiring and operating renewable energy projects.

Key Growth Factors
The Corporation's future growth will be affected by the following key factors:

- Demand for renewable energy;
- Stable and long-term government policies for the procurement of new renewable energy capacity, whether through requests for proposals or other mechanisms;
- Its capacity to evaluate and secure the best prospective sites for the development of new projects in cooperation with local communities;
- Its ability to enter into attractive PPAs and obtain the required environmental and other permits;
- Its ability to adequately forecast total construction costs, expected revenues and expected expenses for each project;
- Its ability to make accretive acquisitions; and
- Its ability to finance its growth.

Key Geographic Markets
In Canada, in response to its commitments under the Paris Agreement, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change and Canada's Mid-Century Low Greenhouse Gas Strategy and the Paris Agreement on Climate Change. The federal government's commitments on climate include phasing out coal-fired generation by 2030, introducing a national low-carbon fuel standard and implementing a national price on carbon by the end of 2018. The Corporation continues to seek potential opportunities and participate in requests for proposals, when available, across the country. While there are no current requests for proposal (RFP) in Quebec, Ontario or British Columbia, the Corporation is well positioned to take advantage of longer term opportunities due to our operational presence.

Since 2007, France has put in place a strategy for developing renewable energies within its territory. The French onshore wind market is very active with the objective, announced in October 2016, of reaching 22,000 to 26,000 MW of wind capacity in 2023 from about 12,000 MW in 2016. The feed-in-tariff contract structure has been changed to a contract for difference ("CfD contract") system under which wind farms of up to six turbines will sell their electricity directly to the market and receive the difference between the target price and the market price under a 20-year CfD contract. Larger wind farms will have the option to participate in auction processes to be granted a similar CfD contract. In 2016, the Corporation established its presence in France with the acquisition of nine wind farms. In 2017, it acquired an additional six wind projects and deployed a local development team to secure projects that could be submitted for CfD contracts. It continues to assess a number of other renewable energy opportunities. Recently, the French government has restated its strong commitment towards renewable energy by adopting a number of measures to accelerate the development process of projects, which helps make France a key market for Innergex.

In the United States, the Corporation increased its presence with its recent acquisition and will continue to assess potential opportunities in light of the existence of renewable portfolio standards (RPS) in several states and the increasing procurement of renewable energy. Twenty-nine states, Washington, D.C. and three territories have adopted a RPS, while eight states and one territory have set renewable energy goals. Hawaii currently has the most ambitious target of 100% renewable energy by 2045 and California is currently on track to meet its target of 50% renewable by the end of 2030. In addition, a growing number of cities and corporations are looking to source their operations with renewable energy exclusively through Corporate PPAs, which will create new opportunities for industry growth.

Iceland's electricity supply is generated from nearly 100% renewable resources. Further power demand growth is expected to be driven by continued growth in the data centre industry and an emerging silicon manufacturing industry. The Corporation will selectively assess future growth opportunities in Iceland.

In Latin America, demand for electricity remains strong and governments are seeking to increase the production of renewable energy, for which they have ample resources. Many countries in Europe have adopted ambitious GHG emissions reduction targets and governments are seeking to reduce their dependency on conventional forms of generation, both of which developments require a greater proportion of renewable energy in these countries' energy portfolios. There are a number of markets to which the Corporation believes it can largely transpose its business model for developing and operating renewable energy assets.

Pursue Growth Opportunities Through Acquisitions

Acquisitions are an important component of the Corporation's business strategy. More specifically, the Corporation will seek acquisitions that will enable it to gain a foothold and develop a critical mass in identified target markets internationally. It will also seek acquisitions in order to consolidate its leadership position in the Canadian renewable energy industry. As it has done in the past, Innergex will continue to focus on hydroelectric, wind and solar power generation assets. The Corporation could also grow through expansion into other forms of renewable energy production if profitable opportunities arise.

Maintain Capacity for Delivering Results

The Corporation does business in a competitive industry. The experience and dedication of its management team constitute an important asset. Through careful management, it has established a track record of completing projects by the commercial operation start date specified in their PPA while adhering to the established construction budgets. The Corporation's employees possess the specialized knowledge and skills necessary to carry out its business. The Corporation can also rely on a network of technical, financial and legal partners and has proved its ability to complement its internal capabilities with efficient use of external consultants when required. In addition, the Corporation retains the services of several engineering firms to assist with the feasibility analysis of its projects. As at the date of this MD&A, the Corporation employed a total of 375 people (including Cartier Wind Energy employees).

KEY PERFORMANCE INDICATORS

The Corporation measures its performance using key performance indicators.

- Power generation comparison with a long-term average in megawatt-hours (“MWh”) and gigawatt-hours (“GWh”);
- Adjusted EBITDA, Adjusted EBITDA Margin and Adjusted EBITDA Proportionate;
- Adjusted Net Earnings;
- Free Cash Flow; and
- Payout Ratio.

The Corporation believes that these indicators are important, as they provide management and the reader with additional information about the Corporation's production and cash generating capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods.

These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

SELECTED ANNUAL INFORMATION

	Year ended December 31		
	2017	2016	2015
PRODUCTION			
Power generated (MWh)	4,394,210	3,521,645	2,987,637
LTA (MWh)	4,763,836	3,364,907	3,054,642
Production as percentage of LTA	92%	105%	98%
STATEMENT OF EARNINGS			
Revenues	400,263	292,785	246,869
Adjusted EBITDA[1]	298,728	215,983	183,738
Adjusted EBITDA Margin[1]	74.6%	73.8%	74.4%
Adjusted EBITDA Proportionate[1]	308,343	224,368	193,179
Net earnings (loss)	19,668	32,043	(48,383)
Adjusted Net earnings[1]	16,194	29,076	19,731
Net earnings (loss) attributable to owners of the parent	30,007	35,963	(30,301)
($ per common share - basic)	0.22	0.28	(0.37)
($ per common share - diluted)	0.22	0.28	(0.37)
Weighted average number of common shares (in 000s)	108,427	106,883	102,304
STATEMENT OF FINANCIAL POSITION			
Total assets	4,190,456	3,604,204	3,128,303
Current liabilities	246,844	220,370	185,170
Long-term debt	3,047,583	2,507,236	2,160,438
Other long-term liabilities	349,594	296,526	217,708
Liability portion of convertible debentures	96,246	94,840	93,430
Total non-current liabilities	3,493,423	2,898,602	2,471,576
Non-controlling interests	14,920	14,712	21,907
Equity attributable to owners	435,269	470,520	449,650
DIVIDENDS			
Declared per Class A Preferred Share	0.902	0.902	1.250
Declared per Class C Preferred Share	1.4375	1.4375	1.4375
Declared per common share	0.66	0.64	0.62
PAYOUT RATIO			
Dividends declared on common shares	71,621	68,524	63,646
Free Cash Flow [1, 2]	87,207	75,702	74,386
Payout Ratio [1, 2]	82%	91%	86%

1. Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted EBITDA Proportionate, Adjusted Net Earnings, Free Cash Flow and Payout ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For more information on the calculation and explanation of the Corporation's Free Cash Flow and Payout Ratio, please refer to the "Free Cash Flow and Payout Ratio" section.

Financial year 2017

For the year ended December 31, 2017, the increase in power generated, revenues, Adjusted EBITDA and Adjusted EBITDA Proportionate are attributable mostly to the contribution of the facilities commissioned in 2016 and 2017 and to the wind facilities acquired in France in 2016 and in 2017. The increase was partly offset by lower production at our British Columbia hydro facilities.

The Corporation recorded $19.7 million in net earnings compared to $32.0 million in 2016, mainly due to this year's below-average production compared with last year's above-average production and to challenging post-commissioning activities currently being addressed at the Upper Lillooet River and Mesgi'g Ugju's'n facilities.

The increase in total assets is due mainly to the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières wind farms and the construction of Upper Lillooet River and Boulder Creek hydro facilities.

The increase in long-term debt results mainly from the addition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities, additional drawings on Innergex's credit facilities and the Rougemont-2, Mesgi’g Ugju’s’n, Plan Fleury and Les Renardières financings, the issuance of debentures carrying an 8.0% interest rate to Desjardins for its investment in the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities and the addition of the subordinated debt financing for two of the French subsidiaries, partly offset by the reimbursement of the Mesgi'g Ugju's'n substation loan and scheduled repayment of project-level debts.

The equity attributable to owners decreased due mainly to the declaration of dividends on preferred and common shares in 2017, partly offset by the recognition of $30.0 million in net earnings attributable to the owners of the parent.

Free Cash Flow increased due mainly to higher cash flows from operating activities before changes in non-cash operating working capital items, partly offset by greater scheduled debt principal payments. The Corporation payout ratio was 82% for the year ended December 31, 2017.

Financial year 2016

2016 was marked by Innergex's first oversea acquisitions in France, the acquisition of Walden hydroelectric facility in BC and the commissioning of a hydroelectric facility in BC and a wind farm in Quebec. These factors, along with better results in all hydroelectricity markets except Ontario, positively influenced results, increasing the power generated, revenues and adjusted EBITDA despite the lower wind regime in Quebec.

In 2016, the Corporation recorded $32.0 million in net earnings compared to a net loss of $48.4 million in 2015, which can be explained mainly by the $32.2 million increase in Adjusted EBITDA and by two factors recorded in 2015, namely a $38.2 million net loss on derivative financial instruments and the recognition of a $51.7 million impairment of project development costs. These items were partly offset by higher finance costs, higher amortization and depreciation costs and an income tax expense (compared with a recovery in 2015).

Total assets in 2016 increased due mainly to investments made by the Corporation in the ongoing construction of the Big Silver Creek (commissioned in July 2016), Upper Lillooet River and Boulder Creek hydro projects and the Mesgi'g Ugju's'n wind project (commissioned in December 2016) as well as investments made to acquire the Walden hydro facility and seven French wind farms.

Long-term debt increased mainly due to the acquisitions in France, for which project-level debts were added and debenture carrying an interest rate of 8.0% were issued to Desjardins in the amount of $38.2 million. Additional drawings on Innergex's credit facilities, Stardale's long-term debt increase on its borrowing and additional drawings on the Upper Lillooet River and Boulder Creek, and Mesgi’g Ugju’s’n financings also contributed to an increase in long-term debt, partly offset by the scheduled repayment of project-level debts.

The equity attributable to owners increased due mainly to the recognition of net earnings attributable to owners of the parent of $36.0 million and the issuance of $54.3 million in new common shares, which were partially offset by the declaration of dividends on preferred and common shares in 2016.

Free Cash Flow increased due mainly to higher cash flows from operating activities in 2016 before changes in non-cash operating working capital items and realized losses on derivative financial instruments (none in 2016), which were partly offset by greater scheduled debt principal payments and higher free cash flow attributed to non-controlling interests. The Corporation also decided to invest more to pursue growth opportunities in new international markets, resulting in a higher payout ratio of 91%.

Financial year 2015

The year 2015 results were impacted mostly by the full-year contribution of the Sainte-Marguerite hydroelectric facility in Quebec acquired in June 2014 and the commissioning of the Tretheway Creek hydroelectric facility commissioned at the end of 2015. The Corporation recorded increases in the power generated, revenues and Adjusted EBITDA, which were also positively impacted by above-average wind regimes.

In 2015, the Corporation recorded a $48.4 million net loss, which is attributable mainly to the recognition of an impairment expense of $51.7 million in relation to some project development costs and the negative impact of derivative financial instruments, namely a $119.6 million realized loss on derivative financial instruments partly offset by a $81.4 million unrealized gain on derivative financial instruments.

Total assets in 2015 increased due mainly to investments made in the ongoing construction of the Tretheway Creek (commissioned in October 2015), Big Silver Creek, Upper Lillooet River and Boulder Creek hydro projects and the Mesgi'g Ugju's'n wind project.

Long-term debt increased in 2015 again attributable mainly to the addition of projects-level debt for projects under construction at the time, partly offset by a reduction in the revolving credit term facility. The increase in the liability portion of convertible debentures in 2015 is due to the fact that the Corporation issued $100.0 million of new convertible debentures bearing interest at 4.25% while it redeemed or converted the outstanding principal amount of $80.5 million of the convertible debentures bearing interest at 5.75%.

The equity attributable to owners and non-controlling interests decreased in 2015 due mainly to the recognition of a net loss and the declaration of dividends on preferred and common shares in 2015, which was partially offset by the issuance of new common shares upon conversion, at the holders' request, of convertible debentures bearing interest at 5.75%.

Free Cash Flow increased in 2015, attributable mainly to an increase in Adjusted EBITDA, which was partly offset by the increase in dividends resulting from the greater number of shares outstanding, yielding a lower Payout Ratio of 86%.

DEVELOPMENTS IN 2017

Conversion of Big Silver Creek Loan

On January 31, 2017, the $197.2 million non-recourse construction and term project financing closed by Big Silver Creek Power Limited Partnership on June 22, 2015, for the Big Silver Creek River run-of-river hydroelectric project was converted into a 39.5-year term loan.

The loan comprises three facilities or tranches:

- A $51.0 million construction loan carrying a fixed interest rate of 4.57%; it was converted into a 25-year term loan and the principal will begin to be amortized over a 22-year period starting in 2019;
- A $128.3 million construction loan carrying a fixed interest rate of 4.76%; it was converted into a 39.5-year term loan and the principal will be amortized after the 25-year term loan reaches maturity;
- A $17.9 million construction loan carrying a fixed interest rate of 4.76%; it was converted into a 39.5-year term loan and its principal will be reimbursed at maturity.

Financing of the French Subsidiaries

On February 10, 2017, Innergex and Desjardins Group Pension Plan ("RRMD") raised €8.5 million of subordinated debt from a French infrastructure fund through their French subsidiaries created for the acquisition of wind farms in France in April 2016. The subordinated loan carries an interest rate of 7.25% and has an eight-year tenor; its principal will be reimbursed at maturity.

Completion of the Acquisition of the Yonne Wind Farm

On February 21, 2017, Innergex completed the acquisition of the 44 MW Yonne wind farm located in northern France. This wind farm acquisition was announced simultaneously to the acquisition of seven wind farms in 2016. At the time, the facility was under construction and its acquisition was to be concluded once the commissioning was completed. The commissioning activities began in the fourth quarter of 2016 and were completed at the end of January 2017. Innergex owns a 69.55% interest in the wind farm and RRMD owns the remaining 30.45%.

The total purchase price amounted to €35.2 million ($49.0 million) subject to certain adjustments and included €3.8 million ($5.3 million) of working capital. A €10.0 million ($13.9 million) deposit had already been provided by the Corporation when the acquisition was first announced in March 2016. Innergex's net additional investment to pay for the purchase totalled €10.7 million ($14.9 million) and it fulfilled its obligation to pay its portion of the purchase price through available funds. The remainder of the purchase price was paid by RRMD in the amount of €6.2 million ($8.6 million) and with the funds generated by the financing of two French subsidiaries on February 10, 2017, in the amount of €8.4 million ($11.6 million).

In its first full year of operation, the Yonne wind farm's average annual production is estimated to reach 100,400 MWh, enough to power about 21,000 French households. The facility is expected to generate revenues and Adjusted EBITDA of approximately €8.6 million ($12.0 million) and €7.2 million ($10.0 million) respectively. All the electricity it produces is sold under a PPA with Electricité de France ("EDF") for an initial term of 15 years. The PPA comes to term on October 19, 2031.

The project financing of €59.5 million ($82.8 million), which is already in place, will remain at the acquired project level.

Extension and Amendment of the Revolving Credit Facilities

On February 21, 2017, Innergex executed a Fifth Amended and Restated Credit Agreement of its then existing $425 million revolving credit facilities. These amendments give the Corporation flexibility in borrowing in euros using EURIBOR loans. The Corporation also extended its revolving term from 2020 to 2021 (except for one lender of $42.5 million, whose commitment remained in effect until 2020) to provide greater financing flexibility. Moreover, a Letter of Credit Facility of up to $30 million guaranteed by Export Development Canada (EDC) has been added and put in place.

On October 31, 2017, the Corporation announced that it had increased its revolving credit facilities by $50 million and added a new lender to the syndicate of lenders. It also extended the maturity of its revolving facility from December 2021 to December 2022 for all its lenders to provide greater flexibility.

Acquisition of Rougemont 1-2 and Vaite

On May 24, 2017, Innergex completed the acquisition of three wind projects in France's Bourgogne–Franche-Comté region with an aggregate capacity of 119.5 MW. Innergex owns a 69.55% interest in the wind farms while RRMD owns the remaining 30.45%.

The equity's purchase price was approximately €51.4 million ($76.2 million), subject to certain adjustments. Innergex's net share of the purchase price amounted to about €31.3 million ($46.4 million) and was paid through funds available under its corporate revolving credit facilities. The remainder of the purchase price was paid by RRMD in the amount of €20.1 million ($29.8 million).

Non-recourse debts related to the projects, which were already in place, amounted to €174.3 million ($258.4 million) at the end of construction and will remain at each project level.

The aggregate annual power generation is expected to reach 278,200 MWh , enough to power about 58,400 French households. All the electricity produced by these wind farms is sold under fixed-price PPAs, with a portion of the price being adjusted according to inflation indexes, for an initial term of 15 years, with EDF. Innergex is expecting revenues of approximately €23.5 million ($34.8 million) and Adjusted EBITDA of approximately €18.2 million ($26.9 million) for the first 12 months of operations.

The Rougemont-1 and Vaite wind farm were commissioned in the second quarter of 2017 while the Rougemont-2 wind farm reached commercial operation during the fourth quarter of 2017.

Acquisition of Plan Fleury and Les Renardières

On August 25, 2017, Innergex completed the acquisition of two wind projects in France's Champagne-Ardenne region with an aggregate capacity of 43 MW. Innergex owns a 69.55% interest in the wind farms while RRMD owns the remaining 30.45%.

The equity's purchase price was €27.4 million ($40.8 million), subject to certain adjustments. Innergex's net share of the purchase price amounted to about €16.5 million ($24.2 million) and was paid through funds available under its corporate revolving credit facilities. The remainder of the purchase price was paid by RRMD in the amount of €10.7 million ($15.7 million).

The non-recourse debts related to the projects, which were already in place, totalled €72.0 million ($105.7 million) at the end of construction and will remain in place at each project level.

The aggregate annual power generation is expected to reach 118,000 MWh once the two projects are in commercial operation, enough to power about 24,775 French households. All the electricity produced by these wind farms will be sold under fixed-price PPAs with EDF, with a portion of the price being adjusted according to inflation indexes, for an initial term of 15 years. Innergex is expecting revenues of approximately €9.9 million ($14.5 million) and Adjusted EBITDA of approximately €8.2 million ($12.0 million) for the first 12 months of operation.

The Plan Fleury (22.0 MW) wind farm began commercial operation during the third quarter. The wind project Les Renardières (21.0 MW) was commissioned in the fourth quarter of 2017.

Normal Course Issuer Bid

On August 15, 2017, Innergex announced that it has received approval from the Toronto Stock Exchange (TSX) to proceed with a normal course issuer bid on its common shares (the "Bid").

Under the Bid, the Corporation may purchase for cancellation up to 2,000,000 of its common shares, corresponding to approximately 1.84% of the 108,640,790 issued and outstanding common shares of the Corporation as at August 14, 2017. The Bid commenced on August 17, 2017, and will terminate on August 16, 2018.

Purchases will be made on behalf of the Corporation by a registered broker through the facilities of the TSX at prevailing market prices.

The Corporation believes that the market price of its Common shares may, from time to time, not reflect the inherent value of the Corporation and that purchases of its Common shares pursuant to the Bid may represent an appropriate and desirable use of the Corporation's funds. Therefore, the Corporation believes that it is in its best interest to proceed with the Bid.

On November 14, 2017, the Corporation announced that it has received approval from the Toronto Stock Exchange (TSX) to implement an automatic purchase plan under the Bid. The Corporation has entered into an automatic purchase plan agreement with a designated broker to allow for purchases of its common shares during times when it would ordinarily not be permitted to do so due to self-imposed black-out periods or regulatory restrictions.

Arrangement Agreement to Acquire Alterra Power Corp.

On October 30, 2017, the Corporation and Alterra Power Corp. announced that they had entered into an arrangement agreement (the "Arrangement Agreement") pursuant to which Innergex would acquire at a price of $8.25 per share all of the issued and outstanding common shares of Alterra ("Alterra Common Shares") for an aggregate consideration of $1.1 billion, including the assumption of Alterra's debt (the "Transaction"). The Transaction was subject to approval by Alterra's shareholders and other customary closing conditions. Pursuant to the Transaction, Alterra shareholders would receive an aggregate consideration, which would consist of approximately 25% in cash and 75% in common shares of Innergex (the "Innergex Common Shares").

On December 14, 2017, Alterra shareholders were asked to vote on a special resolution approving the Arrangement Agreement in accordance with its terms during a Special Meeting of Shareholders. The special resolution was approved by 99.89% of the 32,994,488 votes cast by Alterra shareholders.

On February 6, 2018, Innergex completed the Transaction.

OPERATIONAL HIGHLIGHTS

Alterra complements Innergex's current operating, under construction and prospective projects, resulting in increased geographic and technological diversification through meaningful presence in the United States and Icelandic power markets as well as the addition of geothermal power generation to Innergex's production mix. The transaction significantly accelerates Innergex's growth profile.

Alterra's and Innergex's experienced management teams, with a track record of successfully developing and operating renewable energy projects in various jurisdictions, will play an important role in developing the large growth pipeline of the combined company.

TRANSACTION DETAILS
Pursuant to the Transaction, Alterra shareholders had the right to elect to receive either $8.25 in cash ("Cash Alternative") or 0.5563 Innergex common shares ("Share Alternative") for each Alterra common share, subject in each case to the pro-ration, such that the aggregate consideration paid to all Alterra shareholders consisted of approximately 25% in cash and 75% in Innergex common shares.

The Innergex common shares that were issuable to Alterra shareholders with the Transaction correspond to an ownership of approximately 18% of the combined corporation. One member of the Alterra board of directors joined the Innergex board of directors on the closing of the Transaction.

SUPPORT OF KEY SHAREHOLDERS
Innergex entered into a support agreement with Ross Beaty, Executive Chairman of Alterra, and certain related entities that had control over approximately 31% of Alterra's issued and outstanding common shares. Under the support agreement, Mr. Beaty and the related entities have elected to receive Innergex Common Shares for the entirety of the Alterra Common Shares held by them and agreed to a 12-month holding period with respect to the Innergex Common Shares received by them as a result of the Transaction.

Further information regarding the Transaction is contained in a management proxy circular prepared by Alterra and filed and mailed to Alterra shareholders on November 16, 2017. Copies of the Arrangement Agreement, support and voting agreements and management proxy circular are available on SEDAR under Alterra's profile at sedar.com.

FINANCING
Innergex has structured the financing of the cash portion of the Transaction in order to maintain a strong and flexible balance sheet that provides for ample liquidity to fully fund Innergex's development portfolio post-Transaction. To that end, the Caisse de dépôt et placement du Québec provided Innergex with a five-year $150 million subordinated unsecured term loan at a 5.128% interest rate.

Innergex has also increased its revolving credit facilities by $225 million to $700 million, led by BMO Capital Markets, National Bank Financial Inc. and TD Securities as co-lead arrangers and joint book managers. The maturity of the revolving credit facilities remains December 2022.

SUMMARY OF ALTERRA PROJECTS

Operating	Energy	Country	Ownership	Net Installed Capacity (MW)	Projected 2018 Revenues ($M)[3 4]	Projected 2018 Gross Adjusted EBITDA[2] ($M)[3 4]	Projected 2018 Net Adjusted EBITDA[5] ($M)[4]
Shannon[1]	Wind	U.S.	50%	102	23.4	12.7	6.4
East Toba	Hydro	Canada	40%	59	75.6 [6]	58.2 [6]	23.3 [6]
Montrose Creek	Hydro	Canada	40%	35			
Reykjanes 1-2	Geothermal	Iceland	54%	54	72.1 [7]	34.9 [7]	18.8 [7]
Svartsengi[8]	Geothermal	Iceland	54%	40			
Dokie 1	Wind	Canada	26%	37	36.6	26.5	6.8
Jimmie Creek	Hydro	Canada	51%	32	19.7	15.6	8.0
Kokomo[1]	Solar	U.S.	90%	6	1.0	0.8	0.7
Spartan[1]	Solar	U.S.	100%	14	2.0	1.6	1.6
Operating				**379**			**65.6**

Under Construction	Energy	Country	Ownership[1]	Net Installed Capacity (MW)	Projected Year One Revenues ($M)[3 4]	Expected Full Year One Gross Adjusted EBITDA[2] ($M)[3 4]	Expected Full Year One Net Adjusted EBITDA[5] ($M)[4]
Flat Top[1]	Wind	U.S.	51%	102	26.7	11.9	6.1
Brúarvirkjun	Hydro	Iceland	54%	5	4.2	3.2	1.7
Under Construction				**107**			**7.8**

Prospective projects[9]	Energy	Country	Ownership	Net Capacity (MW)
Advanced-Stage				
Foard City (PTC Qualified)[10]	Wind	U.S.	100%	350
Reykjanes 4	Geothermal	Iceland	54%	16
Boswell Springs (PTC Qualified)[10]	Wind	U.S.	100%	320
Advanced-Stage				**686**
Other Prospective Projects				>**3,500**

1 The percentage of ownership reflects Innergex's portion of sponsor equity partnership.
2 Gross Adjusted EBITDA is not a recognized measure by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
3 Corresponding to 100% of the facility
4 U.S. dollar and Icelandic króna figures converted to Canadian dollars at USD-CAD rate of 1.289 and CAD-ISK rate of 78.35.
5 Net Adjusted EBITDA is not a recognized measure by IFRS and therefore may not be comparable to those presented by other issuers. It corresponds to Gross Adjusted EBITDA multiplied by ownership percentage. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
6 Reflects the combined metrics for Toba Montrose (East Toba and Montrose Creek).
7 Reflects the combined metrics for HS Orka (Reykjanes 1-2 and Svartsengi).
8 The Svartsengi geothermal facility also sells water with a gross thermal energy capacity of 190 MW.
9 There is no certainty that these projects will materialize on time or on budget and the number of MWs per project could vary.
10 "PTC" stands for U.S. renewable electricity production tax credit.

The acquisition of Alterra included a 54% interest in a subsidiary which owns a 30% stake of the Blue Lagoon Geothermal Spa and Resort located in Iceland. Innergex intends to review the future ownership of this non-core asset.

Conversion of the Mesgi'g Ugju's'n loan

On November 27, 2017, the $311.7 million non-recourse construction and term project financing closed by Mesgi'g Ugju's'n (MU) Wind Farm, L.P. on September 24, 2015, for the Mesgi'g Ugju's'n wind farm project was converted into a 19.5-year term loan. On October 27, 2017, a $49.2 million construction loan was repaid with the proceeds of the scheduled reimbursement of the MU electrical substation.

(in thousands of Canadian dollars, except as noted and amounts per share)

The loan comprises two facilities or tranches:

- A $103.0 million floating-rate construction loan carrying a swap-fixed interest rate of 3.54%; it was converted into a 9.5-year term loan and the principal is amortized over the term of the loan;
- A $159.5 million construction loan carrying a fixed interest rate of 4.28%; it was converted into a 19.5-year term loan and the principal will be amortized after the 9.5-year term loan reaches maturity.

Power Purchase Agreement Up for Renewal

The PPA for the 8.0 MW St-Paulin hydroelectric facility located in Quebec reached the end of its initial 20-year term in November 2014. The Corporation had sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 20-year term. Following initial discussions, the Corporation and Hydro-Québec could not reach agreement on the renewal terms and conditions and the Corporation subsequently filed a notice of arbitration. The Corporation has agreed with Hydro-Québec to suspend its arbitration proceeding until a decision is made in another arbitration proceeding already under way between Hydro-Québec and other independent power producers. In the meantime, Hydro-Québec has agreed to maintain the terms and conditions of the St-Paulin PPA until 30 days following the decision in the other arbitration proceeding. The decision in the other arbitration was rendered on March 24, 2017. The agreement on the renewal of the PPA was signed on November 27, 2017, for a 20-year term ending November 28, 2034.

The PPA for the 5.5 MW Windsor hydroelectric facility located in Quebec reached the end of its initial 20-year term in January 2016 and the Corporation sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 20-year term. Following initial discussions, the Corporation and Hydro-Québec could not reach agreement on the renewal terms and conditions and the Corporation subsequently filed a notice of arbitration. On November 27, 2017, the renewal of the PPA was signed for a 20-year term ending January 21, 2036.

The PPA for the Brown Lake hydroelectric facility located in British Columbia reached the end of its initial 20-year term in December 2016 and the Corporation has signed a series of a temporary extension agreement while it continues negotiations with BC Hydro as part of the normal course of a PPA renewal.

The first PPA for the Sainte-Marguerite hydroelectric facility located in Quebec will reach the end of its initial 25-year term in December 2018 and the Corporation has sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 25-year term. Discussions on the renewal terms and conditions will take place during the year.

The PPA for the Chaudière hydroelectric facility located in Quebec will reach the end of its initial 20-year term in March 2019 and the Corporation has sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 20-year term. Discussions on the renewal terms and conditions will take place during the year.

Commissioning Activities

	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project costs		Expected first full year	
					Estimated[1] ($M)	As at Dec. 31 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1 3] ($M)
HYDRO (British Columbia)								
Upper Lillooet River	66.7	81.4	334.0	40	345.8	344.5	33.0	27.5
Boulder Creek	66.7	25.3	92.5	40	124.4	124.0	9.0	7.5
WIND (France)								
Plan Fleury	69.6	22.0	65.3	15	60.6 [2]	59.8 [2]	8.0 [2]	6.7 [2]
Les Renardières	69.6	21.0	52.4	15	52.9 [2]	52.2 [2]	6.4 [2]	5.3 [2]
Rougemont-2	69.6	44.5	100.3	15	108.9 [2]	104.5 [2]	12.4 [2]	9.6 [2]

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary. These estimates are up-to-date as at the date of the MD&A.
2. Corresponding to 100% of this facility. Euro amounts have been translated at 1.5052.
3. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

(in thousands of Canadian dollars, except as noted and amounts per share)

Upper Lillooet River and Boulder Creek

In the first quarter, the Corporation began commercial operation of the 81.4 MW Upper Lillooet River run-of-river hydroelectric facility located in British Columbia. Construction began in October 2013 and was completed in March 2017. The Commercial Operation Date ("COD") Certificate delivered to BC Hydro shows an effective commissioning date of March 30, 2017. The Upper Lillooet River facility's average annual production is estimated to reach 334,000 MWh, enough to power more than 31,850 households. In its first full year of operation, it is expected to generate revenues and Adjusted EBITDA of approximately $33.0 million and $27.5 million respectively. Estimated Total Project Costs were increased for this project mainly due to challenging post-commissioning activities currently being addressed.

In the second quarter, the Corporation began commercial operation of the 25.3 MW Boulder Creek run-of-river hydroelectric facility in British Columbia. Construction began in October 2013. The COD Certificate delivered to BC Hydro shows an effective commissioning date of May 16, 2017. The Boulder Creek facility's average annual production is estimated at 92,500 MWh, enough to power more than 8,500 households. In its first full year of operation, the facility is expected to generate revenues and Adjusted EBITDA of approximately $9.0 million and $7.5 million respectively.

All the electricity the facilities produce is covered by two 40-year fixed-price power purchase agreements with BC Hydro, which was obtained under that province's 2008 Clean Power Call Request for Proposals and which provides for an annual adjustment to the selling price based on a portion of the Consumer Price Index. On March 17, 2015, the Corporation announced the closing of a $491.6 million non-recourse construction and term project financing for the Boulder Creek and Upper Lillooet River projects, which received the Clean Energy BC's Finance Award for 2015 and the 2016 Hydro Power Deal of the Year from the World Finance Magazine.

The insurance claims process for the forest fire that occurred during construction in 2015 continues, with interim progress payments being made. The Corporation expects to receive an indemnity, which should cover most of the financial consequences from the fire.

Plan Fleury

In the third quarter, the Corporation began commercial operation of the 22.0 MW Plan Fleury wind facility located in Champagne-Ardenne, France. Construction began prior to its acquisition by Innergex and was completed in August 2017. The Declaration of COD under the purchase agreement with EDF shows an effective commissioning date of September 6, 2017. The Plan Fleury facility's average annual production is estimated to reach 65,266 MWh, enough to power more than 13,750 French households.

In its first full year of operation, it is expected to generate revenues and Adjusted EBITDA of approximately €5.5 million ($8.0 million) and €4.6 million ($6.7 million) respectively. All the electricity the facility produces is covered by an initial 15-year fixed-price PPA with EDF, with a portion of the price being adjusted according to inflation indexes.

Les Renardières

In the fourth quarter, the Corporation began commercial operation of the 21.0 MW Les Renardières wind facility located in Champagne-Ardenne, France. Construction began prior to its acquisition by Innergex and was completed in November 2017. The Declaration of COD under the purchase agreement with EDF shows an effective commissioning date of November 18, 2017. The Les Renardières facility's average annual production is estimated to reach 52,427 MWh, enough to power more than 11,200 French households.

In its first full year of operation, it is expected to generate revenues and Adjusted EBITDA of approximately €4.4 million ($6.4 million) and €3.6 million ($5.3 million) respectively. All the electricity the facility produces is covered by an initial 15-year fixed-price PPA with EDF, with a portion of the price being adjusted according to inflation indexes.

Rougemont-2

In the fourth quarter, the Corporation began commercial operation of the 44.5 MW Rougemont-2 wind facility located in Bourgogne-Franche-Comté, France. Construction began prior to its acquisition by Innergex and was completed in November 2017. The Declaration of COD under the purchase agreement with EDF shows an effective commissioning date of December 1, 2017. The Rougemont-2 facility's average annual production is estimated to reach 100,340 MWh, enough to power more than 21,400 French households.

In its first full year of operation, it is expected to generate revenues and Adjusted EBITDA of approximately €8.4 million ($12.4 million) and €6.5 million ($9.6 million) respectively. All the electricity the facility produces is covered by an initial 15-year fixed-price PPA with EDF, with a portion of the price being adjusted according to inflation indexes.

Construction Activities

The total project costs for the Development Projects are as follows:

	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project costs	Expected first full year	
						Estimated[1] ($M)	Revenues[1] ($M)	Adjusted EBITDA[1 4] ($M)
WIND (United States)								
Flat Top	51.0	200.0	2018	872.9	13	404.8 [2]	26.7 [2]	11.9 [2]
HYDRO (Iceland)								
Brúarvirkjun	53.9	10.0	2020	80.0	- [5]	52.3 [3]	4.2 [3]	3.2 [3]
		210.0		952.9		457.1	30.9	15.1

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary. These estimates are up-to-date as at the date of the MD&A.
2. Corresponding to 100% of this facility. US amounts have been translated at 1.289
3. Corresponding to 100% of this facility. Icelandic króna amounts have been translated at CAD-ISK rate of 78.35
4. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
5. Power generated to be sold on the retail market.

Flat Top
The Flat Top wind project was acquired in the first quarter of 2018 as part of the Alterra acquisition. Construction was already under way at the time of the acquisition.

As at the date of this MD&A, construction for the 200 MW wind farm continues on time and on budget, with all road construction, turbine foundations and collector lines now completed. All 100 turbines have been delivered to site and the majority have been fully erected. Commissioning is under way to allow connection to the grid and the project has begun delivering limited test power. The Corporation expects commercial operations to commence in the first quarter of 2018.

The funding of the tax equity investment and retirement of the credit facility are expected to occur on or near the commercial operation date. The Corporation does not expect to make any further equity contributions towards the Flat Top project, which is currently being funded solely by the construction loan facility and equity contributions by our sponsor equity partner.

Brúarvirkjun
The Brúarvirkjun hydro project was acquired in the first quarter of 2018 as part of the Alterra acquisition. Site preparation work was already under way at the time of the acquisition.

As at the date of this MD&A, site preparation work, including laydown areas and access roads to the powerhouse and intake and supply of the owner's site camp, had been completed. Construction of the project is scheduled to start in 2018 following receipt of the final construction permit with commissioning expected to occur in early 2020.

OPERATING RESULTS

Electricity production last year was 92% of the LTA production due mainly to lower production from challenging post-commissioning activities currently being addressed at the Upper Lillooet River and Mesgi'g Ugju's'n facilities, below-average water flows in British Columbia and below-average wind regimes in France, which were partly offset by above-average water flows in the hydroelectric sector in Quebec and Ontario.

Production increased 25%, revenues 37% and Adjusted EBITDA 38%. These increases are attributable mainly to the contribution of the facilities commissioned in 2016 and 2017 and to the wind facilities acquired in France in 2016 and 2017; they were partly offset by lower production at our British Columbia hydro facilities.

The Corporation's operating results for the year ended December 31, 2017, are compared with the operating results for the same period in 2016.

(in thousands of Canadian dollars, except as noted and amounts per share)

Electricity Production

When evaluating its operating results, a key performance indicator for the Corporation is to compare actual electricity generation with a long-term average for each hydroelectric facility, wind farm and solar farm. These LTA are determined to allow long-term forecasting of the expected power generation for each of the Corporation's facilities.

	Year ended December 31					
	2017			2016		
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	748,128	699,930	107%	710,686	699,930	102%
Ontario	87,743	74,544	118%	54,341	74,544	73%
British Columbia	1,902,568	2,175,579	87%	1,906,877	1,670,734	114%
United States	37,276	46,800	80%	46,864	46,800	100%
Subtotal	2,775,715	2,996,853	93%	2,718,768	2,492,008	109%
WIND						
Quebec	1,158,681	1,238,990	94%	683,150	724,710	94%
France	419,757	490,366	86%	77,664	110,297	70%
Subtotal	1,578,438	1,729,356	91%	760,814	835,007	91%
SOLAR						
Ontario	40,057	37,627	106%	42,063	37,892	111%
Total	4,394,210	4,763,836	92%	3,521,645	3,364,907	105%

1. The Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for consistency's sake, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

During the year ended December 31, 2017, the Corporation's facilities produced 4,394,210 MWh of electricity or 92% of the LTA of 4,763,836 MWh. Overall, the hydroelectric facilities produced 93% of their LTA due mainly to lower production from challenging post-commissioning activities currently being addressed at the Upper Lillooet River facility and below-average water flows in British Columbia, partly offset by above-average water flows in Quebec and Ontario. Overall, the wind farms produced 91% of their LTA due to lower production from post-commissioning activities currently being addressed at the Mesgi'g Ugju's'n facility and below-average wind regimes in France. Wind regimes in France have lately trended well below the historical average, which explains the lower production. The Stardale solar farm produced 106% of its LTA due to an above-average solar regime. For more information on operating segment results, please refer to the "Segment Information" section.

The 25% production increase compared with the same period last year is due mainly to the contribution of the facilities commissioned in 2016 and 2017 and the wind farms acquired in France in 2016 and in 2017 and to higher production at some of our Quebec and Ontario hydro facilities, which was partly offset by lower production at our British Columbia hydro facilities.

The overall performance of the Corporation's facilities for the period ended December 31, 2017, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind and solar power generation.

Power Purchase Agreements

As at December 31, 2017, the 54 Operating Facilities sold the generated power under long-term PPAs to rated public utilities or other creditworthy counterparties. For Operating Facilities in Quebec, Ontario and British Columbia as well as in France, PPAs include a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery, except for the Miller Creek hydroelectric facility, for which the price is based on a formula using the Platts Mid-C pricing indices (this facility accounted for less than 1% of revenues in 2017). For the Horseshoe Bend hydroelectric facility in Idaho, 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission.

(in thousands of Canadian dollars, except as noted and amounts per share)

Financial Results

	Year ended December 31		Change	
	2017	2016		
Revenues	400,263	292,785	107,478	37 %
Operating expenses	71,672	51,469	20,203	39 %
General and administrative expenses	17,806	15,045	2,761	18 %
Prospective project expenses	12,057	10,288	1,769	17 %
Adjusted EBITDA[1]	298,728	215,983	82,745	38 %
Adjusted EBITDA margin[1]	74.6%	73.8%		
Finance costs	146,766	95,254	51,512	54 %
Other net expenses	2,453	265	2,188	826 %
Depreciation and amortization	129,429	90,303	39,126	43 %
Share of earnings of joint ventures (note 2)	(4,638)	(2,526)	(2,112)	84 %
Unrealized net gain on financial instruments	(2,245)	(4,292)	2,047	(48)%
Income taxes expenses	7,295	4,936	2,359	48 %
Net earnings	19,668	32,043	(12,375)	(39)%
Net earnings attributable to:				
Owners of the parent	30,007	35,963	(5,956)	(17)%
Non-controlling interests	(10,339)	(3,920)	(6,419)	164 %
	19,668	32,043	(12,375)	(39)%
Basic net earnings per share ($)	0.22	0.28		

1. Adjusted EBITDA and Adjusted EBITDA Margin are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. The Umbata Falls hydroelectric facility and Viger Denonville wind farm are treated as joint ventures and the Corporation's interests in these facilities are required to be accounted for using the equity method. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Revenues

Up 37% to $400.3 million for the year ended December 31, 2017

This increase is attributable mainly to the facilities commissioned in 2016 and 2017 and the wind facilities acquired in 2016 and 2017 in France as well as to higher production at all of our Ontario hydro facilities, which was partly offset by lower production at our British Columbia hydro facilities.

Expenses

Up 32% to $101.5 million for the year ended December 31, 2017

Operating expenses consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes and royalties. For the year ended December 31, 2017, the Corporation recorded operating expenses of $71.7 million ($51.5 million in 2016). The 39% increase for the year is attributable mainly to the commissioning of the Big Silver Creek hydro facility in July 2016, the Mesgi'g Ugju's'n wind farm in December 2016, the Upper Lillooet River hydro facility in March 2017 and the Boulder Creek hydro facility in May 2017 as well as to the acquisition of wind facilities in France in 2016 and 2017. Operating expenses for the year were also impacted by a $3.2 million aggregate payment related to water rights for 2011 and 2012 for Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River, which were reassessed following the decision by the British Columbia Ministry of Forests, Lands and Natural Resource Operations to apply higher rental rates based on the facilities' combined production rather than apply lower rates for each facility based on its individual production, as had previously been the ministry's practice. The Corporation has filed an appeal of this decision with the Environmental Appeal Board. Since 2013, these facilities' water rights fees have been paid at the higher rates. A 49.99% portion of the water rights payment is allocated to the non-controlling interests.

General and administrative expenses consist primarily of salaries, professional fees and office expenses. For the year ended December 31, 2017, general and administrative expenses totalled $17.8 million ($15.0 million in 2016). The 18% increase for the year stems mainly from the greater number of facilities in operation.

(in thousands of Canadian dollars, except as noted and amounts per share)

Prospective project expenses include the costs incurred for the development of Prospective Projects. They are related to the number of Prospective Projects that the Corporation chooses to advance and the resources required to do so. For the year ended December 31, 2017, prospective project expenses totalled $12.1 million ($10.3 million in 2016). The 17% increase for the year is mainly attributable to pursuing opportunities in new international markets, to current and future requests for proposals and expressions of interest in Canadian provinces and to the advancement of a number of prospective projects.

Adjusted EBITDA

Up 38% to $298.7 million for the year ended December 31, 2017

Adjusted EBITDA, which is defined as revenues less operating expenses, general and administrative expenses and prospective project expenses, is a key performance indicator when evaluating the Corporation's financial results. Adjusted EBITDA is not recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

This increase is due mainly to production and revenues from new facilities, partly offset by higher operating expenses, general and administrative expenses and prospective project expenses. The Adjusted EBITDA Margin increased from 73.8% to 74.6% for the year due mainly to the increase in revenues net of expenses, partly offset by the payment related to water rights for 2011 and 2012 in British Columbia made in the first quarter of 2017.

Adjusted EBITDA Proportionate

Up 37% to $308.3 million for the year ended December 31, 2017

Adjusted EBITDA Proportionate, which is defined as Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the joint ventures, is a key performance indicator when evaluating the Corporation's financial results. Adjusted EBITDA Proportionate is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

	Year ended December 31	
	2017	2016
Adjusted EBITDA[1]	298,728	215,983
Innergex's share of Adjusted EBITDA of joint ventures[2]	9,615	8,385
Adjusted EBITDA proportionate[1]	308,343	224,368

1. Adjusted EBITDA and Adjusted EBITDA proportionate are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. Please refer to the "Investments in Joint Ventures" section of this MD&A for more information.

This increase is due mainly to higher Adjusted EBITDA and a higher share of Adjusted EBITDA of joint ventures stemming from higher production at the Umbata Falls and Viger-Denonville facilities.

Finance Costs

Up 54% to $146.8 million for the year ended December 31, 2017

Finance costs include interest on long-term debt and convertible debentures, inflation compensation interest, amortization of financing fees, accretion of long-term debt and convertible debentures, accretion expenses on other liabilities and other finance costs. The increase is due mainly to expenses related to the facilities commissioned or acquired in 2016 and 2017.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 4.43% as at December 31, 2017 (4.79% as at December 31, 2016).

Other Net Expenses

Up to $2.5 million for the year ended December 31, 2017

Other Net Expenses include transaction costs, realized gain on foreign exchange, gain or loss on contingent considerations, other net revenues, loss on disposal of property, plant and equipment and recovery loan payment. The increase is due mainly to higher transaction costs stemming from more time and effort being devoted to acquisitions, partly offset by unrealized contingent consideration.

Depreciation and Amortization

Up 43% to $129.4 million for the year ended December 31, 2017

This increase is attributable mainly to the Big Silver Creek hydro facility commissioned in July 2016, the Mesgi'g Ugju's'n wind farm commissioned in December 2016, the Upper Lillooet River hydro facility commissioned in March 2017, the Boulder Creek hydro facility commissioned in May 2017 and to the French wind farms acquired in 2016 and 2017.

Share of Earnings of Joint Ventures

Share of net earnings of $4.6 million for the year ended December 31, 2017, compared with $2.5 million in 2016

Please refer to the "Investments in Joint Ventures" section for more information.

(in thousands of Canadian dollars, except as noted and amounts per share)

Unrealized Net Gain on Financial Instruments

Unrealized net gain of $2.2 million for the year ended December 31, 2017, compared with $4.3 million in 2016

Derivatives are used by the Corporation to manage its exposure to the risk of rising interest rates on its existing and upcoming debt financing and to reduce the Corporation's foreign exchange risk, thereby protecting the economic value of its projects.

The unrealized net gain on financial instruments for the year ended December 31, 2017, is due to an unrealized gain on the conversion of an intragroup loan and the amortization of the accumulated losses from the pre-hedge accounting period, partly offset by an unrealized net loss on the foreign exchange rate swap due to an unfavourable change in the CAD-EUR foreign exchange rate.

For the corresponding period last year, the Corporation recognized an unrealized net gain on financial instruments of $4.3 million due mainly to a gain on the amortization of the accumulated losses from the pre-hedge accounting period partly offset by an unrealized loss on the conversion of an intragroup loan and to the unfavourable change in the CAD-EUR foreign exchange rate.

In connection with the Alterra transaction, the Corporation entered into bond forward contracts for a total of $50 million to mitigate the risk of interest rate increases before the closing of the transaction. For the period ended December 31, 2017, the Derivatives to be settled upon the closing of the Alterra transaction had a positive value of $0.3 million.

Income Tax Expense

Up 48% to $7.3 million for the year ended December 31, 2017

For the year ended December 31, 2017, the Corporation recorded a current income tax expense of $4.1 million ($3.0 million in 2016) and a deferred income tax expense of $3.2 million (deferred income tax expense of $2.0 million in 2016). The $1.2 million increase in the current income tax expense is due mainly to higher income from wind facilities acquired in December 2016 and 2017 in France. The deferred income tax expense in 2017 is due mainly to the recognition of accounting earnings before income taxes resulting from the Corporation's regular business activities and increasing non–deductible expenses, partly offset by a decrease in the corporate income tax rates in France. In 2016, although the net earnings before the income tax expense were higher, the deferred income tax expense was reduced significantly by much larger tax cuts in 2016 in France than those announced by the French government in 2017.

Net Earnings

Down 39% to $19.7 million for the year ended December 31, 2017

For the year ended December 31, 2017, the Corporation recorded net earnings of $19.7 million (basic and diluted net earnings of $0.22 per share) compared with net earnings of $32.0 million (basic and diluted net earnings of $0.28 per share) in 2016. The $12.4 million decrease in net earnings is attributable mainly to this year's below-average production compared with last year's above-average production and to challenging post-commissioning activities currently being addressed at the Upper Lillooet River and Mesgi'g Ugju's'n facilities, which explains the decrease in net earnings as opposed to the increase in revenues. As a result, the $51.5 million increase in finance costs, the $39.1 million increase in depreciation and amortization and the $2.4 million increase in income taxes were only partly offset by the $82.7 million increase in Adjusted EBITDA, and the $2.1 million increase in share of earnings of joint ventures.

Adjusted Net Earnings

Down 44% to $16.2 million for the year ended December 31, 2017

When evaluating its operating results and to provide a more accurate picture of its operating results, a key performance analysis for the Corporation is the "Adjusted Net Earnings". Adjusted Net Earnings is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Impact on net earnings (loss) of financial instruments	Year ended December 31	
	2017	2016
Net earnings	19,668	32,043
Add (Subtract):		
Unrealized net gain on financial instruments	(2,245)	(4,292)
(Recovery) income tax expense related to above items	(232)	1,215
Share of unrealized net (gain) loss on financial instruments of joint ventures, net of related income tax	(997)	110
Adjusted Net Earnings[1]	16,194	29,076

1. Adjusted Net Earnings is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

(in thousands of Canadian dollars, except as noted and amounts per share)

Excluding gains on financial instruments and the related income taxes, net earnings for the year ended December 31, 2017, would have been $16.2 million, compared with net earnings of $29.1 million in 2016. The decrease is attributable mainly to the factors described in *Net Earnings*.

Non-controlling Interests

Loss of $10.3 million for the year ended December 31, 2017, compared with a loss of $3.9 million in 2016

Non-controlling interests are related to the Harrison Hydro Limited Partnership ("HHLP"), the Creek Power Inc. subsidiaries ("Creek Power"), the Mesgi'g Ugju's'n (MU) Wind Farm, L.P. ("MU"), the Innergex Europe (2015) Limited Partnership ("Innergex Europe"), the Kwoiek Creek Resources Limited Partnership ("Kwoiek"), the Magpie Limited Partnership, the Innergex Sainte-Marguerite S.E.C. entity and the Cayoose Creek Power Limited Partnership and their respective general partners.

The Corporation allocated losses to non-controlling interests mainly related to losses at Innergex Europe due to weak production, at Creek Power due to challenging post-commissioning activities currently being addressed at Upper Lillooet River and at HHLP due to a payment related to water rights for 2011 and 2012, partly offset by revenues at MU.

LIQUIDITY AND CAPITAL RESOURCES

For the year ended December 31, 2017, the Corporation generated cash flows from operating activities of $192.5 million compared with cash flows of $76.8 million for the same period last year. During this year, the Corporation generated funds from financing activities of $24.7 million and used funds for investing activities of $212.0 million mainly to pay for the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières wind farms and the construction of Upper Lillooet River, Boulder Creek and Rougemont-2 facilities, partly offset by a decrease in restricted cash and short-term investments. As at December 31, 2017, the Corporation had cash and cash equivalents amounting to $61.9 million, compared with $56.2 million as at December 31, 2016.

Cash Flows from Operating Activities

Up $115.7 million to $192.5 million for the year ended December 31, 2017

The increase is attributable to a $82.7 million increase in Adjusted EBITDA and a $80.2 million increase in non-cash operating working capital items, partly offset by a $44.1 million increase in interest paid on long-term debt.

Cash Flows from Financing Activities

Down $170.5 million to $24.7 million for the year ended December 31, 2017

The decrease is attributable to a $91.5 million net increase in long-term debt in 2017 compared with a $212.4 million increase in long-term debt and to a $50.0 million private placement of common shares of Innergex with three Desjardins Group-affiliated entities in 2016.

The $91.5 million increase in long-term debt is attributable mainly to the issuance of debentures carrying an 8.0% interest rate to Desjardins for its investment in the acquisitions of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities, to drawings made on the revolving credit facilities related to same facilities acquired, to drawings made on Montjean, Theil-Rabier, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières project financing and to the raising of subordinated debt from a French infrastructure fund via the French subsidiaries, which funds were used to finance a portion of the acquisition of the Yonne facility in France in February 2017. The increase was partly offset by the reimbursement of the Mesgi'g Ugju's'n substation loan, the reimbursement of a loan dedicated to the consumer taxes recoverable from the government for the Yonne facility and by scheduled debt repayments.

Use of Financing Proceeds	Year ended December 31 2017	2016	Change
Proceeds from issuance of long-term debt (including revolving credit facility)	668,856	872,247	
Repayment of long-term debt (including revolving credit facility)	(576,187)	(657,207)	
Payment of deferred financing costs	(1,161)	(2,680)	
Subtotal: net increase in long-term debt	91,508	212,360	(120,852)
Proceeds from issuance of common shares	—	50,000	
Payment of buy-back of common shares	(4,119)	—	
Proceeds from exercise of share options	—	1,034	
Investments from non-controlling interests	16,842	9,565	
Generation of financing proceeds	104,231	272,959	(168,728)
Business acquisitions	(152,797)	(125,493)	
Decrease of restricted cash and short-term investments	70,203	222,978	
Net funds (invested into) withdrawn from the reserve accounts	(85)	1,610	
Additions to property, plant and equipment	(135,656)	(351,258)	
Reductions of (additions to) other long-term assets	1,020	(14,740)	
Net use of financing proceeds	(217,315)	(266,903)	49,588
(Reduction) increase in working capital	(113,084)	6,056	(119,140)

During the year ended December 31, 2017, the Corporation borrowed a net amount of $91.5 million and RRMD invested $16.8 million in equity mainly to pay for the acquisition of the Yonne, Rougemont 1-2, Vaite, Les Renardières and Plan Fleury wind facilities in February, May and August 2017. The net amount borrowed was also used for the construction of the Rougemont-2 facility. The Corporation used $70.2 million in restricted cash mainly to continue construction of the Upper Lillooet River, Boulder Creek, Plan Fleury and Les Renardières facilities.

Cash Flows from Investing Activities

Lower outflow of $43.0 million to $212.0 million for the year ended December 31, 2017

During the period, the main investing activities impacting cash flows were as follows: additions to property, plant and equipment accounted for a $135.7 million outflow ($351.3 million outflow in 2016); fluctuations in restricted cash and short-term investments accounted for a $70.2 million inflow ($223.0 million inflow in 2016); reductions to other long-term assets accounted for a small inflow (additions to other long-term assets for a $14.7 million outflow in 2016); and business acquisitions accounted for a $152.8 million outflow ($125.5 million outflow in 2016) for the acquisition of the Yonne, Rougemont 1-2, Vaite, Les Renardières and Plan Fleury facilities in February, May and August 2017.

Cash and Cash Equivalents

Up $5.7 million to $61.9 million for the year ended December 31, 2017

For the year ended December 31, 2017, cash and cash equivalents increased by $5.7 million (increased by $15.6 million in 2016) as a net result of its operating, financing and investing activities.

(in thousands of Canadian dollars, except as noted and amounts per share)

SHARE CAPITAL STRUCTURE

Information on Capital Stock

Number of Common Shares Outstanding

Weighted average number of common shares outstanding (000s)	Year ended December 31 2017	2016
Weighted average number of common shares	108,427	106,883
Effect of dilutive elements on common shares[1]	820	879
Diluted weighted average number of common shares	109,247	107,762

1. As at December 31, 2017, all of the 2,782,599 stock options (3,331,684 of the 3,457,432 for the year ended December 31, 2016) were dilutive. During the year ended December 31, 2017, none of the 6,666,667 shares that can be issued on conversion of convertible debentures were dilutive (none of the 6,666,667 shares were dilutive for the same period in 2016).

The Corporation's Equity Securities

As at	February 21, 2018	December 31, 2017	December 31, 2016
Number of common shares	132,322,161	108,608,083	108,181,592
Number of 4.25% convertible debentures	100,000	100,000	100,000
Number of Series A Preferred Shares	3,400,000	3,400,000	3,400,000
Number of Series C Preferred Shares	2,000,000	2,000,000	2,000,000
Number of stock options outstanding	2,782,599	2,782,599	3,457,432

As at the opening of the market on February 21, 2018, and since December 31, 2017, the increase in the number of common shares of the Corporation is attributable mainly to the the issuance of 24,327,225 shares on February 6, 2018, related to the acquisition of Alterra and to the issuance of 83,565 shares related to the Corporation's Dividend Reinvestment Plan ("DRIP"), which were partly offset by the 696,712 shares purchased for cancellation under the normal course issuer bid ("NCIB").

As at December 31, 2017, the increase in the number of common shares since December 31, 2016, is attributable mainly to the issuance of 121,378 shares following the exercise of stock options and of 361,195 shares related to the DRIP, net of 56,082 shares purchased for cancellation under the NCIB .

Dividends

The Corporation's dividend policy is determined by its Board of Directors and is based on the Corporation's operating results, cash flows, financial condition, debt covenants, long-term growth prospects, solvency test imposed under corporate law for the declaration of dividends and other relevant factors.

The following dividends were declared by the Corporation:

	Year ended December 31 2017	2016
Dividends declared on common shares[1]	71,621	68,524
Dividends declared on common shares ($/share)	0.66	0.64
Dividends declared on Series A Preferred Shares	3,067	3,067
Dividends declared on Series A Preferred Shares ($/share)	0.902	0.902
Dividends declared on Series C Preferred Shares	2,875	2,875
Dividends declared on Series C Preferred Shares ($/share)	1.4375	1.4375

1. The increase in dividends declared on common shares is attributable to the increase in annual dividend, the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of Innergex common shares in April 2016, to the issuance of shares following the exercise of stock options and to the issuance of shares under the DRIP.

The following dividends will be paid by the Corporation on April 16, 2018:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
02/21/2018	3/30/2018	4/16/2018	0.1700	0.2255	0.359375

On February 21, 2018, the Board of Directors increased the quarterly dividend from $0.165 to $0.170 per common share, corresponding to an annual dividend of $0.68 per common share. This is the fifth consecutive $0.02 annual dividend increase.

Normal Course Issuer Bid

Under the normal course issuer bid on the Corporation's common shares (Common shares) and the normal course issued bid on its Cumulative Rate Reset Preferred Shares, Series A (Series A shares) and Cumulative Redeemable Fixed Rate Preferred Shares, Series C (Series C shares) (collectively, the Bids) covering the period between March 24, 2016 and March 23, 2017, the Corporation did not repurchase any Common shares, Series A shares and Series C shares for cancellation.

In August 2017, the Corporation proceeded with a normal course issuer bid on its common shares (Common shares) (New Bid) covering the period between August 17, 2017, and August 16, 2018. The Corporation may purchase for cancellation up to 2,000,000 of its Common shares, representing approximately 1.84% of the 108,640,790 issued and outstanding Common shares of the Corporation as at August 14, 2017.

Under the New Bid, the Corporation has entered into an automatic purchase plan agreement with a designated broker to allow for purchases of its common shares at times when it would ordinarily not be permitted to do so due to self-imposed black-out periods or regulatory restrictions.

Under the New Bid, between August 17, 2017 and December 31, 2017, the Corporation purchased 56,082 common shares at an average price of $13.85 per share, for an aggregate consideration of $0.8 million. As at the opening of the market on February 21, 2018 and since December 31, 2017, the Corporation has purchased 696,712 common shares at an average price of $13.60 per share, for an aggregate consideration of $9.5 million.

FINANCIAL POSITION

As at December 31, 2017, the Corporation had $4,190 million in total assets, $3,740 million in total liabilities, including $3,157 million in long-term debt, and $450.2 million in shareholders' equity. The Corporation also had a working capital ratio of 0.90:1.00 (1.14:1.00 as at December 31, 2016). In addition to cash and cash equivalents amounting to $61.9 million, the Corporation had restricted cash and short-term investments of $58.7 million and reserve accounts of $50.0 million. The explanations below highlight the most significant changes in the statement of financial position items during the year ended December 31, 2017.

Assets

Highlights of significant changes in total assets during the year ended December 31, 2017

- A $488.2 million increase in property, plant and equipment, due mainly to the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities in 2017 and the construction of the Upper Lillooet River and Boulder Creek facilities, partly offset by the depreciation for the period;
- A $109.2 million increase in intangible assets, due mainly to the acquisition of the Yonne, Rougemont 1-2 , Vaite, Plan Fleury and Les Renardières facilities 2017, partly offset by the amortization.

Working Capital Items

Working capital was negative at $25.2 million, as at December 31, 2017, with a working capital ratio of 0.90:1.00. As at December 31, 2016, working capital was positive at $31.9 million, with a working capital ratio of 1.14:1.00. The decrease in the working capital ratio is due to lower restricted cash and short-term investments, lower accounts receivable and a higher current portion of long-term debt.

(in thousands of Canadian dollars, except as noted and amounts per share)

The Corporation considers its current level of working capital to be sufficient to meet its needs. As at December 31, 2017, the Corporation had $475.0 million in revolving term credit facilities and had drawn $264.0 million and US$13.9 million as cash advances, while $43.7 million had been used for issuing letters of credit, leaving $149.9 million available.

Cash and cash equivalents amounted to $61.9 million as at December 31, 2017, compared with $56.2 million as at December 31, 2016. The increase stems from a greater number of facilities in operation.

Restricted cash and short-term investments amounted to $58.7 million as at December 31, 2017, compared with $89.7 million as at December 31, 2016. The decrease stems mainly from amounts used to pay for construction of the Upper Lillooet River and Boulder Creek facilities and from the cash released upon the conversion of the Big Silver Creek non-recourse construction and term project financing into a term loans, partly offset by the cash cumulated and not distributed since the commissioning of the Mesgi'g Ugju's'n wind farm and from the restricted cash to pay the remaining construction costs for Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities.

Accounts receivable decreased from $98.8 million to $87.5 million between December 31, 2016, and December 31, 2017, due mainly to the reimbursement of $49.3 million for the Mesgi'g Ugju's'n substation receivable from Hydro-Quebec, partly offset by higher accounts receivable due to a greater number of facilities in operation and by a better month of December 2017 compared with December 2016.

Accounts payable and other payables from December 31, 2016, to December 31, 2017, increased from $85.9 million to $91.0 million, due mainly to higher accounts payable from a greater number of facilities in operation and unpaid interests on the debenture issued to Desjardins, partly offset by payment of construction costs related to the Montjean, Theil Rabier, Upper Lillooet River and Boulder Creek facilities.

Current portion of long-term debt amounted to $109.9 million as at December 31, 2017, compared with $99.4 million as at December 31, 2016. The increase stems mainly from payments due on long-term debts of the newly acquired or commissioned facilities, partly offset by the reimbursement of the Mesgi'g Ugju's'n substation loan.

Reserve Accounts

Reserve accounts consist of a hydrology/wind reserve, which was established at the start of commercial operation at a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind regimes and to other unpredictable events, and a major maintenance reserve, which was established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. The Corporation had $50.0 million in long-term reserve accounts as at December 31, 2017, compared with $49.5 million as at December 31, 2016. The minor increase is mainly due to mandatory investments made during the period, partly offset by drawings on reserve accounts.

The availability of funds in the hydrology/wind and major maintenance reserve accounts is restricted by credit agreements.

The Corporation also has reserve accounts for the dismantling of the wind farms in France at the end of their service life. The Corporation had $0.2 million in long-term dismantling reserve accounts as at December 31, 2017.

Property, Plant and Equipment

*Property, plant and equipmen*t are comprised mainly of hydroelectric facilities, wind farms and a solar farm that are either in operation or under construction. As at December 31, 2017, the Corporation had $3,188 million in property, plant and equipment compared with $2,700 million as at December 31, 2016. The increase stems mainly from the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities in 2017 and the construction of the Upper Lillooet River and Boulder Creek facilities, partly offset by the depreciation for the period.

Intangible Assets

Intangible assets consist of various power purchase agreements, permits and licenses. The Corporation had $654.1 million in intangible assets as at December 31, 2017, compared with $544.9 million as at December 31, 2016. The increase is due mainly to the acquisition of the Yonne, Rougemont 1-2 , Vaite, Plan Fleury and Les Renardières facilities and to the consideration of our commitment recorded as liabilities related to future ownership rights owned by First Nations for the Upper Lillooet River, Boulder Creek, Big Silver Creek and Tretheway Creek facilities, partly offset by the amortization.

Goodwill

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The Corporation had $38.6 million in goodwill as at December 31, 2017, compared with $8.3 million as at December 31, 2016. The increase is due to the acquisitions achieved in 2017.

Liabilities and Shareholders' Equity

Derivative Financial Instruments and Risk Management
The Corporation uses derivative financial instruments ("Derivatives") to manage its exposure to the risk of increasing interest rates on its debt financing and its exposure to exchange rate fluctuations on the future repatriation of cash flows from its French operations. The Corporation does not own or issue any Derivatives for speculation purposes.

Interest rate swap contracts allow the Corporation to eliminate the risk of interest rate increases on actual floating-rate debts. These totalled $982.0 million as at December 31, 2017.

Foreign exchange forward contracts allow the Corporation to hedge its exposure to foreign exchange rate on its investments in France. These totalled $579.6 million as at December 31, 2017.

Overall, Derivatives had a net negative value of $62.3 million as at December 31, 2017 (net negative value of $60.1 million as at December 31, 2016). The increase in negative value is due mainly to the negative value of the Derivatives acquired with the 2017 acquisitions, partly offset by the unrealized net gain recognized in the period.

Accrual for Acquisition of Long-Term Assets
Accrual for acquisition of long-term assets consists of long-term debt commitments that have been secured and will be drawn to finance the Corporation's projects. As at December 31, 2017, accrual for acquisition of long-term assets was nil ($37.4 million as at December 31, 2016). The $37.4 million decrease results mainly from payments made in relation to the Mesgi’g Ugju’s’n, Montjean and Theil Rabier facilities, for which drawings were made from the long-term financing in place.

Long-Term Debt
As at December 31, 2017, long-term debt totalled $3,157 million ($2,607 million as at December 31, 2016). The $550.8 million increase results mainly from the addition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities, additional drawings on Innergex's credit facilities and the Rougemont-2, Mesgi’g Ugju’s’n, Plan Fleury and Les Renardières financings, the issuance of debentures carrying an 8.0% interest rate to Desjardins for its investment in the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities and the addition of the subordinated debt financing for two of the French subsidiaries, partly offset by the reimbursement of the Mesgi'g Ugju's'n substation loan and scheduled repayment of project-level debts.

On February 21, 2017, Innergex executed a Fifth Amended and Restated Credit Agreement of its existing $425 million revolving credit facilities. These amendments increase the Corporation's flexibility in borrowing euros through EURIBOR loans. The Corporation also extended its revolving term from 2020 to 2021 to provide greater financing flexibility. Moreover, a Letter of Credit Facility of up to $15 million guaranteed by Export Development Canada (EDC) was added and put in place.

On October 31, 2017, Innergex increased its revolving credit facilities by $50 million to $475 million and added a new lender to the syndicate of lenders. It also extended the maturity of its revolving facility from December 2021 to December 2022 to provide greater financing flexibility.

On February 6, 2018, Innergex increased its revolving credit facilities by $225 million to $700 million and added a new lender to the syndicate of lenders. This increase enables the Corporation to pursue the development and construction of its portfolio. The maturity of the revolving credit facilities remains December 2022.

As at December 31, 2017, 94% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (99% as at December 31, 2016).

Since the beginning of the 2017 fiscal year, the Corporation and its subsidiaries have met all the financial and non-financial conditions related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements or trust indentures entered into by various subsidiaries of the Corporation could limit the capacity of these subsidiaries to transfer funds to the Corporation. These restrictions could have a negative impact on the Corporation's ability to meet its obligations.

	December 31, 2017	December 31, 2016
Total long-term debt	3,190,809	2,634,619
Deferred financing costs	(33,351)	(27,986)
	3,157,458	2,606,633
Current portion of long-term debt	(109,875)	(99,397)
Long-term portion	3,047,583	2,507,236

Other Liabilities

Other liabilities, including amounts shown in current liabilities, consist of contingent considerations, asset retirement obligations, various liabilities related to future ownership rights owned by First Nations and interest payable on the Innergex Sainte-Marguerite, S.E.C. debenture relating to the Corporation's facilities. As at December 31, 2017, other liabilities totalled $80.0 million ($27.5 million in 2016). The increase is mostly attributable to the $23.9 million actualized liabilities related to future ownership rights owned by First Nations for the Upper Lillooet River, Boulder Creek, Big Silver Creek and Tretheway Creek facilities, the $19.1 million asset retirement obligations related to the facilities acquired in 2017 and to the $9.3 million interest payable related to the Sainte-Marguerite facility.

Convertible debentures

The convertible debentures currently outstanding bear interest at a rate of 4.25% per annum, payable semi-annually on August 31 and February 28 of each year. They are convertible at the holder’s option into common shares of the Corporation at a conversion price of $15.00 per share, representing a conversion rate of 66.6667 common shares per each thousand of dollars of principal amount of convertible debentures. They will mature on August 31, 2020, and will not be redeemable before August 31, 2018, except in certain limited circumstances.

The convertible debentures are subordinated to all other indebtedness of the Corporation.

As at December 31, 2017, the liability portion of convertible debentures stood at $96.2 million and the equity portion stood at $1.9 million ($94.8 million and $1.9 million as at December 31, 2016).

Shareholders' Equity

As at December 31, 2017, the Corporation's shareholders' equity totalled $450.2 million, including $14.9 million of non-controlling interests, compared with $485.2 million as at December 31, 2016, which included $14.7 million of non-controlling interests. This $35.0 million decrease in total shareholders' equity is attributable mainly to $77.6 million in dividends declared on common and preferred shares, partly offset by the recognition of $19.7 million in net earnings, the recognition of other items of comprehensive income totaling $12.8 million, a $9.4 million net investment of non-controlling interest and $5.1 million in shares issued under the DRIP.

Contractual Obligations

As at December 31, 2017	Total	Under 1 year	1 to 3 years	4 to 5 years	Thereafter
Long-term debt including convertible debentures	3,340,784	109,539	281,837	495,493	2,453,915
Interest on long-term debt and convertible debentures	2,658,610	143,377	349,028	248,676	1,917,529
Purchase (Contractual) obligations[1]	60,130	3,899	7,551	7,541	41,139
Others	261,354	13,784	33,164	35,017	179,389
Total contractual obligations	6,320,878	270,599	671,580	786,727	4,591,972

1. Purchase obligations are derived mainly from engineering, procurement and construction contracts.

Contingencies

The acquisition of Cloudworks Energy Inc. realized in 2011 provides for the potential payment of additional amounts to the vendors over a period commencing on the acquisition date and ending in 2056. The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation expects and would result in incremental accretion to the Corporation net of these payments. The maximum aggregate amount of all deferred payments under this acquisition was limited to a present value amount of $35.0 million as at the acquisition date. In 2017, the Corporation recorded a $0.9 million gain on contingent considerations, offsetting the loss recorded in 2016. The balance of the contingent consideration, payable to Cloudworks Energy Inc. vendors is nil as at December 31, 2017.

(in thousands of Canadian dollars, except as noted and amounts per share)

In connection with the Magpie acquisition, the Corporation assumed an obligation to pay contingent consideration to the Minganie Regional County Municipality until the convertible debenture issued by Magpie Limited Partnership is converted. Upon conversion, the Minganie Regional County Municipality will be entitled to a participation of 30% in Magpie Limited Partnership.

Off-Balance-Sheet Arrangements

As at December 31, 2017, the Corporation had issued letters of credit totaling $66.6 million to meet its obligations under its various PPAs and other agreements. Of this amount, $43.7 million was issued under its revolving term credit facilities, either on a temporary basis during the construction of the Upper Lillooet River and Boulder Creek facilities, which ended recently, or for projects in operations, with the remainder being issued under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $36.2 million in corporate guarantees used mainly to guarantee the long-term currency hedging instruments of its European operations and to support the performance of the Brown Lake and Miller Creek hydroelectric facilities and the construction of the Mesgi'g Ugju's'n facility.

FREE CASH FLOW AND PAYOUT RATIO

Free Cash Flow and Payout Ratio calculation[1]	Trailing 12 months ended December 31		
	2017	2016	2015
Cash flows from operating activities	192,451	76,753	4,557
Add (Subtract) the following items:			
Changes in non-cash operating working capital items	(23,782)	56,442	(8,275)
Maintenance capital expenditures net of proceeds from disposals	(3,973)	(2,730)	(3,553)
Scheduled debt principal payments	(67,572)	(43,220)	(31,813)
Free Cash Flow attributed to non-controlling interests[2]	(10,425)	(8,571)	(2,550)
Dividends declared on Preferred shares	(5,942)	(5,942)	(7,125)
Cash receipt for wheeling services to be provided by the Harrison Hydro L.P. to other facilities[3]	—	—	3,327
Adjust for the following elements:			
Transaction costs related to realized acquisitions	6,450	2,970	261
Realized losses on derivative financial instruments	—	—	119,557
Free Cash Flow	87,207	75,702	74,386
Dividends declared on common shares	71,621	68,524	63,646
Payout Ratio	82%	91%	86%
Dividends declared on common shares and paid in cash[4]	67,990	63,346	57,613
Payout Ratio - after the impact of the DRIP	78%	84%	77%

1. Free Cash Flow and Payout ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of the MD&A for more information.
2. The portion of Free Cash Flow attributed to non-controlling interests is subtracted, regardless of whether or not an actual distribution to non-controlling interests is made, in order to reflect the fact that such distributions may not occur in the period they are generated.
3. These amounts represent cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to the Big Silver Creek facility, 49.99% of which was included in the Free Cash Flow attributed to non-controlling interests.
4. Represents dividends declared on common shares outstanding that were not registered in the DRIP at the time of the declaration; the dividends declared on common shares registered in the DRIP were paid in common shares.

(in thousands of Canadian dollars, except as noted and amounts per share)

Free Cash Flow

When evaluating its operating results, a key performance indicator for the Corporation is the cash flows available for distribution to common shareholders and for reinvestment to fund the Corporation's growth. Free Cash Flow is a non-IFRS measure that the Corporation calculates as cash flows from operating activities before changes in non-cash operating working capital items, less maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments and preferred share dividends declared. It also subtracts the portion of Free Cash Flow attributed to non-controlling interests regardless of whether an actual distribution to non-controlling interests is made in order to reflect the fact that such distribution may not occur in the period the Free Cash Flow is generated, and adds back cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their PPAs. The Corporation also adjusts for other elements that represent cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity. Such adjustments include adding back transaction costs related to realized acquisitions (which are financed at the time of the acquisition) and adding back realized losses or subtracting realized gains on derivative financial instruments used to hedge the interest rate on project-level debt prior to securing such debt or the exchange rate on equipment purchases.

For the year ended December 31, 2017, the Corporation generated Free Cash Flow of $87.2 million compared with $75.7 million for the corresponding period last year. The increase in Free Cash Flow is due mainly to higher cash flows from operating activities before changes in non-cash operating working capital items, partly offset by greater scheduled debt principal payments.

Payout Ratio

The Payout Ratio represents the dividends declared on common shares divided by Free Cash Flow. The Corporation believes it is a measure of its ability to sustain current dividends and dividend increases as well as its ability to fund its growth.

For the year ended December 31, 2017, the dividends on common shares declared by the Corporation amounted to 82% of Free Cash Flow compared with 91% for the corresponding period last year. This positive change results mainly from the recent commissioning of the Mesgi’g Ugju’s’n, Upper Lillooet River and Boulder Creek facilities and the acquisition of wind facilities in 2016 and 2017 which generated higher Free Cash Flow, partly offset by higher dividend payments as a result of the increase in annual dividend, higher number of common shares outstanding due to the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of Innergex common shares in April 2016 and to additional shares following the exercise of stock options and issued under the DRIP.

The Payout Ratio reflects the Corporation's decision to invest yearly in advancing the development of its Prospective Projects, which investments must be expensed as incurred. The Corporation considers such investments essential to its long-term growth and success, as it believes that the greenfield development of renewable energy projects offers the greatest potential internal rates of return and represents the most efficient use of management's expertise and value-added skills. For the year ended December 31, 2017, the Corporation incurred prospective project expenses of $12.1 million compared with $10.5 million for the corresponding period last year. This 17% increase for the year is mainly attributable to pursuing opportunities in new international markets, to current and future requests for proposals and expressions of interest in Canadian provinces and to the advancement of a number of prospective projects. Excluding these discretionary expenses, the Corporation's Payout Ratio would have been approximately 10% points lower for the year ended December 31, 2017, and approximately 11% points lower for the prior year.

Furthermore, given the anticipated increase in cash flows from operations, the project-level financing secured for the project and the additional equity provided by the DRIP, the Corporation does not expect to require additional equity in order to complete its Flat Top and Brúarvirkjun projects currently under construction.

PROJECTED FINANCIAL PERFORMANCE

As at December 31, 2017, the Corporation had 54 Operating Facilities with a net installed capacity of 1,124 MW (gross 1,846 MW) and annualized consolidated long-term average production of 5,036 GWh.

The increase in installed capacity and in the number of facilities in operation in 2017 reflects the commissioning of the Upper Lillooet River and Boulder Creek hydro facilities as well as the acquisition of Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières wind farms.

In 2017, Power Generated was expected to increase 31%, Revenues were expected to increase 44%, Adjusted EBITDA was expected to increase 44%, but lower-than-LTA production negatively impacted growth, resulting in respective increases of 25%, 37% and 38%.

On February 6, 2018, the Corporation completed the acquisition of Alterra. Therefore, as of the date of this MD&A, the Corporation has 63 Operating Facilities with a net installed capacity of 1,502 MW (gross 2,686 MW) and annualized consolidated long-term average production of 6,315 GWh. The Alterra acquisition also included two projects under development, namely the Flat Top wind farm in Texas, USA and the Brùarvirkjun hydro facility in Iceland, whose construction activities the Corporation will continue.

	2018		2017		2016	
Power Generated (GWh)	approx.	+41%	4,394	+25%	3,522	+18%
Revenues	approx.	+40%	400,263	+37%	292,785	+19%
Adjusted EBITDA	approx.	+27%	298,728	+38%	215,983	+18%
Adjusted EBITDA proportionate	approx.	+43%	308,343	+37%	224,368	+16%
Number of facilities in operation	64		54		46	
Net installed capacity (MW)	1,604		1,124		909	
Consolidated LTA production, annualized (GWh)	6,315		5,036		4,111	

The Corporation makes certain projections to provide readers with an indication of its business activities and operating performance. These projections take into account the facilities acquired with the Alterra acquisition but do not take into account possible acquisitions, divestments or additional Development Projects. Projected increases in production and revenues reflect production levels in line with the long-term average production. The increase in Adjusted EBITDA reflects a significant increase in general and administrative expenses following the acquisition of Alterra.

(in thousands of Canadian dollars, except as noted and amounts per share)

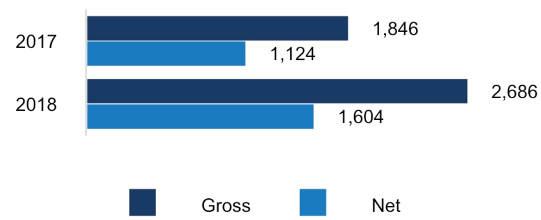
Projected Installed Capacity

The Corporation believes that installed capacity provides a good indication of the size and magnitude of its operations.

With the Alterra acquisition completed on February 6, 2018, and the contribution of the Flat Top wind farm to be commissioned at the end of the first quarter of 2018, the Corporation expects its net installed capacity to increase from 1,124 MW (gross $1,846 MW) at the end of 2017 to 1,604 MW (gross 2,686 MW) in 2018, corresponding to a 43% increase (gross 46%).

Net installed capacity reflects proportional share of the total capacity attributable to Innergex based on its ownership interest in each facility. Installed capacity includes the Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville facilities, which are treated as joint ventures and accounted for using the equity method.

Installed Capacity (MW)



Projected Long-Term Average Production (LTA)

A key performance indicator for the Corporation is to compare actual electricity generation with the expected LTA production for each facility.

With the addition of HS Orka, the Corporation expects its annualized consolidated LTA production to increase from 5,036 GWh at the end of 2017 to 6,315 GWh in 2018, corresponding to a 25% increase.

Consolidated LTA production is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville facilities, which are treated as joint ventures and accounted for using the equity method.

Annualized Consolidated LTA Production (GWh)

	December 31, 2017	December 31, 2018
Hydro	3,019	3,019
Wind	1,979	1,979
Solar	38	38
Geothermal	—	1,279
Total	5,036	6,315

(in thousands of Canadian dollars, except as noted and amounts per share)

Projected Adjusted EBITDA

A key performance indicator for the Corporation is Adjusted EBITDA generation.

With the addition of HS Orka, the Corporation expects in 2018 to generate Adjusted EBITDA of approximately $379.7 million, compared with $298.7 million in 2017. This corresponds to an increase of approximately 27% for 2018 compared with 2017.

Adjusted EBITDA is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville facilities, which are treated as joint ventures and accounted for using the equity method.

It should be noted that Adjusted EBITDA does not take into account the impact of interest and principal payments on the Corporation's existing debt and on the project-level debt financing. Nor does it take into account any potential acquisitions or other development opportunities.

Adjusted EBITDA is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Adjusted EBITDA ($M)

Projected Adjusted EBITDA Proportionate

A key performance indicator for the Corporation is the Adjusted EBITDA Proportionate.

With the Alterra acquisition completed on February 6, 2018, and the contribution of the Flat Top wind farm to be commissioned at the end of the first quarter of 2018, the Corporation expects in 2018 to generate Adjusted EBITDA Proportionate of approximately $439.8 million compared with $308.3 million in 2017. This corresponds to an increase of approximately 43% for 2018 compared with 2017.

Adjusted EBITDA Proportionate reflects the fact that some of the Corporation's facilities are not wholly owned. These include the Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville facilities, which are treated as joint ventures and accounted for using the equity method. The Adjusted EBITDA Proportionate does not take into account any potential acquisitions or other development opportunities.

Adjusted EBITDA Proporationate is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Adjusted EBITDA Proportionate ($M)

	December 31, 2017	December 31, 2018
Adjusted EBITDA	298.7	379.7
Dokie 1 (26%)	—	5.8
East Toba (40%)	—	14.6
Flat Top (51%)	—	6.8
Jimmie Creek (51%)	—	7.9
Kokomo (90%)	—	0.7
Montrose Creek (40%)	—	8.7
Shannon (50%)	—	5.9
Spartan (100%)	—	1.5
Umbata Falls (49%)	5.1	3.8
Viger-Denonville (50%)	4.5	4.4
Adjusted EBITDA Proportionate	308.3	439.8

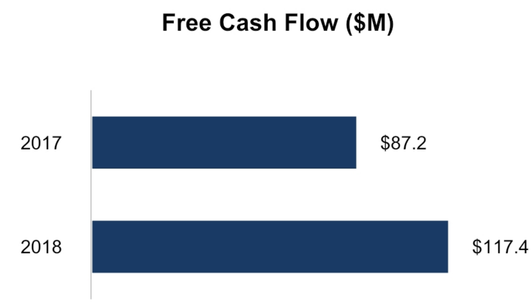
(in thousands of Canadian dollars, except as noted and amounts per share)

Projected Free Cash Flow

Another key performance indicator for the Corporation is the Free Cash Flow generated from its operations and available for distribution to common shareholders and for reinvestment to fund its growth.

With the Alterra acquisition completed on February 6, 2018, and the contribution of the Flat Top wind farm to be commissioned at the end of the first quarter of 2018, the Corporation expects in 2018 to generate Free Cash Flow of approximately $117.4 million compared with $87.2 million in 2017. This corresponds to an increase of approximately 35% for 2018 compared with 2017 and will reflect the cash flows generated by the Corporation's 64 Operating Facilities at that time, after taking into account maintenance capital expenditures, scheduled debt principal payments, preferred share dividends and the portion of Free Cash Flow attributed to non-controlling interests.

Free Cash Flow is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.



For more information on the principal assumptions used in determining projected financial information and the principal risks and uncertainties related thereto, please refer to the "Forward-Looking Information" section.

SEGMENT INFORMATION

Geographic Segments

As at December 31, 2017, the Corporation had interests in 30 hydroelectric facilities, seven wind farms and one solar farm in Canada, 15 wind farms in Europe and one hydroelectric facility in the United States. The Corporation operates in three principal geographical areas, which are detailed below.

	Year ended December 31	
	2017	2016
Revenues		
Canada	344,440	278,723
Europe	52,300	9,836
United States	3,523	4,226
	400,263	292,785

	As at	
	December 31, 2017	December 31, 2016
Non-current assets, excluding derivatives financial instruments and deferred tax assets		
Canada	2,977,859	3,005,720
Europe	973,740	318,924
United States	7,052	7,365
	3,958,651	3,332,009

Canada

Revenues up 24% to $344.4 million for the year ended December 31, 2017

The increase in Canadian revenues is attributable mainly to the contribution of the recently commissioned facilities, namely the Big Silver Creek hydro facility commissioned in July 2016, the Mesgi'g Ugju's'n wind farm commissioned in December 2016, the Upper Lillooet River hydro facility commissioned in March 2017 and the Boulder Creek hydro facility commissioned in May 2017, which were partly offset by lower revenues from the British Columbia hydro facilities.

For the year ended December 31, 2017, the decrease in non-current assets, excluding derivative financial instruments and deferred income tax assets in Canada, stems mainly from amortization and depreciation, partly offset by the construction of the Upper Lillooet River and Boulder Creek facilities.

Europe

Revenues up 432% to $52.3 million for the year ended December 31, 2017

The increase in European revenues is attributable mainly to the wind facilities acquired in 2016 and 2017.

For the period ended December 31, 2017, the change in non-current assets, excluding derivative financial instruments and deferred income tax assets in Europe, stems from the wind facilities acquired in France between February and August 2017.

United States

Revenues down 17% to $3.5 million for the year ended December 31, 2017

The decrease in revenues can mainly be explained by a voluntary limitation in production of the Horseshoe Bend hydro facility in the second quarter due to unusually high water volumes; this prevented sand accumulation in the canal, which can damage the facility and be costly to remove.

For the period ended December 31, 2017, the decrease in non-current assets is attributable mainly to depreciation.

Operating Segments

As at December 31, 2017, the Corporation had four operating segments: hydroelectric generation, wind power generation, solar power generation and site development.

(in thousands of Canadian dollars, except as noted and amounts per share)

Through its hydroelectric, wind power and solar power generation segments, the Corporation sells electricity produced by its hydroelectric, wind and solar facilities to publicly owned utilities or other creditworthy counterparties. Through its site development segment, Innergex analyzes potential sites and develops hydroelectric, wind and solar facilities up to the commissioning stage.

The accounting policies for these segments are the same as those described in the "Significant Accounting Policies" section of the Corporation's audited consolidated financial statements for the year ended December 31, 2017. The Corporation evaluates performance based on Adjusted EBITDA and accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind or solar power generation segments are accounted for at cost.

The operations of the Corporation's operating segments are conducted by different teams, as each segment has different skill requirements.

	SUMMARY OPERATING RESULTS				
	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Year ended December 31, 2017					
Power generated (MWh)	2,775,715	1,560,425	40,057	18,013	4,394,210
Revenues	226,211	155,307	16,824	1,921	400,263
Expenses:					
Operating expenses	44,151	26,098	678	745	71,672
General and administrative expenses	9,934	7,271	144	457	17,806
Prospective project expenses	—	—	—	12,057	12,057
Adjusted EBITDA[1]	172,126	121,938	16,002	(11,338)	298,728
Year ended December 31, 2016					
Power generated (MWh)	2,718,768	760,814	42,063	—	3,521,645
Revenues	211,881	63,238	17,666	—	292,785
Expenses:					
Operating expenses	37,197	13,515	757	—	51,469
General and administrative expenses	8,459	4,090	152	2,344	15,045
Prospective project expenses	—	—	—	10,288	10,288
Adjusted EBITDA[1]	166,225	45,633	16,757	(12,632)	215,983

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

	FINANCIAL POSITION				
	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
As at December 31, 2017					
Goodwill	8,269	30,311	—	—	38,580
Total assets	2,425,646	1,651,537	101,449	11,824	4,190,456
Total liabilities	2,093,158	1,516,245	105,061	25,803	3,740,267
Acquisition of property, plant and equipment during the period	18,804	352,968	12	185,884	557,668
As at December 31, 2016					
Goodwill	8,269	—	—	—	8,269
Total assets	1,993,033	1,003,964	108,231	498,976	3,604,204
Total liabilities	1,537,791	847,148	113,538	620,495	3,118,972
Acquisition of property, plant and equipment during the year	3,420	219,813	11	369,723	592,967

(in thousands of Canadian dollars, except as noted and amounts per share)

Hydroelectric Generation Segment

Revenues up 7% to $226.2 million for the year ended December 31, 2017

For the year ended December 31, 2017, this segment produced 93% of the LTA compared with production at 109% of the LTA last year. The decrease in the percentage of the LTA is attributable mainly to below-average water flows in British Columbia.

The increase in revenues compared with last year is due mainly to the contribution of the Big Silver Creek, Upper Lillooet River and Boulder Creek hydroelectric facilities commissioned between July 2016 and May 2017, partly offset by lower production at most of our British Columbia hydro facilities. Expenses for the year were higher due mainly to a greater number of facilities in operation and a $3.2 million aggregate payment related to water rights for 2011 and 2012 for Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River, which were reassessed following the decision by the British Columbia Ministry of Forests, Lands and Natural Resource Operations to apply higher rental rates based on the facilities' combined production rather than applying lower rates for each facility based on its individual production, as had previously been the ministry's practice. Since 2013, the facilities' water rights fees have been paid at the higher rates. A 49.99% portion of the water rights payment is allocated to the non-controlling interests.

The increase in total assets since December 31, 2016, stems mainly from the Upper Lillooet River and Boulder Creek hydroelectric projects being transferred from the Site Development Segment to the Hydroelectric Generation Segment following their commissioning in March and May 2017 respectively, which was partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2016, is attributable mainly to the transfer of the project financing of the Upper Lillooet River and Boulder Creek projects from the Site Development Segment to the Hydroelectric Generation Segment following their commissioning, which was partly offset by the scheduled repayment of long-term debt.

Wind Power Generation Segment

Revenues up 146% to $155.3 million for the year ended December 31, 2017

For the year ended December 31, 2017, this segment produced 91% of the LTA compared with production at 91% of the LTA last year. The below-LTA production is due mainly to post-commissioning activities currently being addressed at the Mesgi'g Ugju's'n facility and below-average wind regimes in France.

Revenues increased due mainly to the commissioning of the Mesgi'g Ugju's'n wind farm, despite challenging post-commissioning activities and to the wind facilities acquired in France in 2016 and 2017.

The increase in total assets since December 31, 2016, is mainly attributable to the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities in February, May and August 2017 respectively. The increase was partly offset by the reimbursement by Hydro-Québec of the Mesgi'g Ugju's'n substation recevable and depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2016, is attributable mainly to the acquisition of the Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities in February, May and August 2017, which was partly offset by the scheduled repayment of long-term debt.

Solar Power Generation Segment

Revenues down 5% to $16.8 million for the year ended December 31, 2017

For the year ended December 31, 2017, this segment produced 106% of the LTA compared with production at 111% of the LTA last year.

The decrease in revenues can be explained by lower solar irradiation than last year.

The decrease in total assets since December 31, 2016, results mainly from depreciation of property, plant and equipment and from amortization of intangible assets.

The decrease in total liabilities since December 31, 2016, results mainly from the scheduled repayment of long-term debt.

Site Development Segment

Expenses up 5% to $13.3 million for the year ended December 31, 2017

This increase in expenses is mainly due to investments made to pursue growth opportunities. Production and revenues recorded in the quarter stemmed from eight turbines being in operation at the Rougemont-2 facility for the months of October and November. The facility reached full commissioning on December 1, 2017, and production was then allocated in the Wind Generation Segment.

The decrease in total assets since December 31, 2016, stems mainly from the Upper Lillooet River and Boulder Creek hydro projects being transferred from the Site Development Segment to the Hydroelectric Generation Segment following their commissioning in March and May 2017.

Since December 31, 2016, the decrease in total liabilities is mainly due to the transfer of the Upper Lillooet River and Boulder Creek projects from the Site Development Segment to the Hydroelectric Generation Segment following their commissioning in March and May 2017.

QUARTERLY FINANCIAL INFORMATION

	Three months ended			
(in millions of dollars, unless otherwise stated)	Dec. 31, 2017	Sept. 30, 2017	June 30, 2017	Mar. 31, 2017
Power generated (MWh)	1,106,060	1,243,099	1,322,781	722,273
Revenues	108.0	108.2	109.5	74.5
Adjusted EBITDA[1]	80.1	81.8	85.9	50.9
Realized and unrealized net (loss) gain on financial instruments	(1.4)	(1.0)	(0.5)	5.1
Net earnings (loss)	3.5	4.4	14.1	(2.3)
Net earnings attributable to owners of the parent	7.1	5.9	14.6	2.5
Net earnings attributable to owners of the parent ($ per share – basic and diluted)	0.05	0.04	0.12	0.01
Dividends declared on preferred shares	1.5	1.5	1.5	1.5
Dividends declared on common shares	17.9	17.9	17.9	17.9
Dividends declared on common shares, $ per share	0.165	0.165	0.165	0.165

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

(in millions of dollars, unless otherwise stated)	Dec. 31, 2016	Sept. 30, 2016	June 30, 2016	Mar. 31, 2016
Power generated (MWh)	848,967	831,840	1,176,451	664,387
Revenues	73.3	69.3	87.8	62.5
Adjusted EBITDA[1]	50.3	51.2	66.9	47.7
Realized and unrealized net gain (loss) on financial instruments	2.2	(1.3)	2.2	1.3
Net earnings	8.8	0.4	15.7	7.2
Net earnings attributable to owners of the parent	9.8	3.4	14.4	8.3
Net earnings attributable to owners of the parent ($ per share – basic and diluted)	0.08	0.02	0.12	0.07
Dividends declared on preferred shares	1.5	1.5	1.5	1.5
Dividends declared on common shares	17.3	17.3	17.3	16.6
Dividends declared on common shares, $ per share	0.160	0.160	0.160	0.160

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Comparing the results for the most recent quarters illustrates the seasonality that is characteristic of the Corporation's production and the variability of power generated, revenues and Adjusted EBITDA from quarter to quarter. As the Corporation's annualized consolidated LTA is 60% hydroelectric, this seasonality can be explained by water flows that are normally at their highest in the second quarter due to the snow melt season and at their lowest in the first quarter due to the cold temperatures, which limit precipitation in the form of rain. However, premiums for the electricity generated during the coldest months of the year included in some PPAs of the Corporation's hydroelectric facilities attenuate this seasonality. Wind regimes are generally best in the first quarter, while solar irradiation is at its highest during the summer months and at its lowest during the winter months.

Readers may expect the net earnings or losses to reflect this seasonality characteristic of run-of-river hydroelectric facilities, wind farms and solar farms. However, other factors also influence these figures, some of which have a relatively stable quarter-to-quarter impact while others are more variable. For the Corporation, the factors responsible for the largest fluctuations in net earnings (loss) are the unrealized and realized gains (losses) on financial instruments arising from the increase (decrease) in benchmark interest rates, and foreign exchange fluctuations. Historical analysis of net earnings (losses) should take these factors into account. It should be borne in mind that the unrealized changes in market value of derivative financial instruments result from interest rate fluctuations and foreign exchange fluctuations and do not have an impact on the Corporation's Adjusted EBITDA, finance costs, cash flows from operating activities, Free Cash Flow or Payout Ratio.

FOURTH QUARTER RESULTS

Electricity Production

	Three months ended December 31					
	2017			2016		
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	195,682	181,486	108%	182,925	181,486	101%
Ontario	24,341	21,212	115%	14,250	21,212	67%
British Columbia	283,954	372,987	76%	409,994	315,077	130%
United States	5,215	5,223	100%	2,751	5,223	53%
Subtotal	509,192	580,908	88%	609,921	522,998	117%
WIND						
Quebec	415,222	346,067	120%	197,096	255,495	77%
France	176,089	200,365	88%	36,048	53,817	67%
Subtotal	591,311	546,432	108%	233,144	309,312	75%
SOLAR						
Ontario	5,557	5,701	97%	5,902	5,741	103%
Total	1,106,060	1,133,041	98%	848,967	838,051	101%

1. The Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for the sake of consistency, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

During the three-month period ended December 31, 2017, the Corporation's facilities produced 1,106 GWh of electricity or 98% of the LTA of 1,133 GWh. Overall, the hydroelectric facilities produced 88% of their LTA due to challenging post-commissioning activities currently being addressed at the Upper Lillooet River facility and below-average water flows at most of the British Columbia facilities. Overall, the wind farms produced 108% of their LTA due to the above-average wind regime in Quebec and to compensation received from the manufacturer for non-availability of equipment at the Mesgi'g Ugju's'n facility, partly offset by the below-average wind regime in France. The solar farm produced 97% of its LTA due to the average solar regime. For more information on operating segment results, please refer to the "Segment Information" section.

(in thousands of Canadian dollars, except as noted and amounts per share)

Financial Results

	Three months ended December 31			
	2017	2016	Change	
Revenues	107,973	73,265	34,708	47 %
Operating expenses	20,278	15,674	4,604	29 %
General and administrative expenses	3,784	4,508	(724)	(16)%
Prospective project expenses	3,852	2,819	1,033	37 %
Adjusted EBITDA[1]	80,059	50,264	29,795	59 %
Adjusted EBITDA margin[1]	74.1%	68.6%		
Finance costs	40,398	26,228	14,170	54 %
Other net expenses	2,480	895	1,585	177 %
Depreciation and amortization	34,476	25,614	8,862	35 %
Share of earnings of joint ventures[2]	(1,707)	(2,919)	1,212	(42)%
Unrealized net loss (gain) on derivative financial instruments	1,350	(2,172)	3,522	(162)%
Income tax expense (recovery of)	(451)	(6,147)	5,696	(93)%
Net earnings	3,513	8,765	(5,252)	(60)%
Net earnings attributable to				
Owners of the parent	7,107	9,835	(2,728)	(28)%
Non-controlling interests	(3,594)	(1,070)	(2,524)	236 %
	3,513	8,765	(5,252)	(60)%
Basic net earnings per share ($)	0.05	0.08		

1. Adjusted EBITDA and Adjusted EBITDA Margin are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. The Umbata Falls hydroelectric facility and Viger Denonville wind farm are treated as joint ventures and the Corporation's interests in these facilities are required to be accounted for using the equity method. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Revenues

Up 47% to $108.0 million for the three-month period ended December 31, 2017

This increase is attributable mainly to the contribution of the recently commissioned Mesgi'g Ugju's'n, Upper Lillooet River and Boulder Creek facilities as well as to the acquisition of the Montjean, Theil-Rabier, Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities. The increase was partly offset by lower production at most of the British Columbia hydro facilities.

Expenses

Up 21% to $27.9 million for the three-month period ended December 31, 2017

For the three-month period ended December 31, 2017, the Corporation recorded operating expenses of $20.3 million ($15.7 million in 2016), general and administrative expenses of $3.8 million ($4.5 million in 2016) and prospective project expenses of $3.9 million ($2.8 million in 2016). The increase in operating expenses compared with the same period last year is due mainly to the commissioning of the Mesgi'g Ugju's'n, Upper Lillooet River and Boulder Creek facilities as well as to the acquisition of the Montjean, Theil-Rabier, Yonne, Rougemont 1-2, Vaite, Plan Fleury and Les Renardières wind farms. The decrease in general and administrative expenses stems mainly from more salaries being classified as transaction costs and prospective expenses due to the greater time and effort being devoted to acquisitions and advancing prospective projects. The increase in prospective project expenses is attributable mainly to pursuing opportunities in new international markets, to current and future requests for proposals and expressions of interest in Canadian provinces and to the progress of a number of prospective projects.

(in thousands of Canadian dollars, except as noted and amounts per share)

Adjusted EBITDA

Up 59% to $80.1 million for the three-month period ended December 31, 2017

Adjusted EBITDA, which is defined as revenues less operating expenses, general and administrative expenses and prospective project expenses, is a key performance indicator when evaluating the Corporation's financial results. Adjusted EBITDA is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

The increase is mainly due to higher revenues net of expenses, as discussed above.

Adjusted EBITDA Proportionate

Up 62% to $83.2 million for the three-month period ended December 31, 2017

Adjusted EBITDA Proportionate, which is defined as Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the joint ventures, is a key performance indicator when evaluating the Corporation's financial results. Adjusted EBITDA Proportionate is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

	Three months ended December 31	
	2017	2016
Adjusted EBITDA[1]	80,059	50,264
Innergex's share of Adjusted EBITDA of joint ventures[2]	3,140	1,231
Adjusted EBITDA proportionate[1]	83,199	51,495

1. Adjusted EBITDA and Adjusted EBITDA proportionate are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. Please refer to the "Investments in Joint Ventures" section of this MD&A for more information.

This increase is due mainly to higher Adjusted EBITDA and a higher share of Adjusted EBITDA of joint ventures stemming from higher production and revenues at the Umbata Falls and Viger-Denonville facilities.

Finance Costs

Up 54% to $40.4 million for the three-month period ended December 31, 2017

The increase is due mainly to expenses related to recently commissioned facilities, namely the Mesgi'g Ugju's'n, Upper Lillooet River and Boulder Creek facilities, and to the wind farms acquired in France in December 2016 and in 2017.

Other Net Expenses

Up 177% to $2.5 million for the three-month period ended December 31, 2017

The increase is due mainly to higher transaction costs stemming from more time and effort being devoted to acquisitions.

Depreciation and Amortization

Up 35% to $34.5 million for the three-month period ended December 31, 2017

The increase is attributable mainly to recently commissioned facilities, namely the Mesgi'g Ugju's'n, Upper Lillooet River and Boulder Creek facilities and to the wind farms acquired in France in December 2016 and in 2017.

Net Earnings

Down 60% to $3.5 million for the three-month period ended December 31, 2017

Net Earnings of $3.5 million (basic and diluted net earnings of $0.05 per share), compared with a net earnings of $8.8 million (basic and diluted net earnings of $0.08 per share) in 2016, were recorded by the Corporation in the quarter. The decrease is explained mainly by the $14.2 million increase in finance costs, the $8.9 million increase in depreciation and amortization and the $5.7 million decrease in income tax recovery. Net earnings were also impacted by the recognition of an unrealized net loss on derivative financial instruments compared with a gain for the three-months ended December 31, 2016, and to a lower share of earnings of joint ventures compared with the same quarter in 2016. These factors were partly offset by the $29.8 million increase in Adjusted EBITDA.

(in thousands of Canadian dollars, except as noted and amounts per share)

Adjusted Net Earnings

Down 40% to $3.9 million for the three-month period ended December 31, 2017

When evaluating its operating results and to provide a more accurate picture of its renewable energy operating results, a key performance analysis for the Corporation is the "Adjusted Net Earnings." Adjusted Net Earnings is not recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Impact on net earnings of financial instruments	Three months ended December 31	
	2017	2016
Net earnings	3,513	8,765
Add (Subtract):		
Unrealized net loss (gain) on financial instruments	1,350	(2,172)
(Recovery) income tax expense related to above items	(888)	467
Share of unrealized net gain on financial instruments of joint ventures, net of related income tax	(123)	(655)
Adjusted Net Earnings	3,852	6,405

1. Adjusted Net Earnings is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Excluding losses and gains on financial instruments and the related income taxes, net earnings for the three-month period ended December 31, 2017, would have been $3.9 million compared with net earnings of $6.4 million in 2016. The decrease is attributable mainly to the factors described in *Net Earnings*.

INVESTMENTS IN JOINT VENTURES

The Corporation's material joint ventures at the end of the reporting period were Umbata Falls Limited Partnership ("Umbata Falls, L.P.") (49% interest) and Parc éolien communautaire Viger-Denonville, s.e.c. (Viger-Denonville, L.P.) (50% interest). A summary of the electricity production and financial information for the Corporation's material joint ventures is presented below. The summarized financial information corresponds to amounts shown in the joint ventures' financial statements prepared in accordance with IFRS.

Electricity Production

	Three months ended December 31					
	2017			2016		
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA
Umbata Falls	45,551	33,037	138%	27,392	33,037	83%
Viger-Denonville	24,190	20,300	119%	19,309	20,300	95%

1. Corresponds to 100% of the facility's electricity production and LTA.

	Year ended December 31					
	2017			2016		
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA
Umbata Falls	136,833	109,101	125%	111,019	109,101	102%
Viger-Denonville	73,369	72,400	101%	68,865	72,400	95%

1. Corresponds to 100% of the facility's electricity production and LTA.

(in thousands of Canadian dollars, except as noted and amounts per share)

Innergex's share of Adjusted EBITDA of joint ventures

	Three months ended December 31	
	2017	2016
Innergex's share of Adjusted EBITDA[1] of joint ventures:		
Umbata Falls (49%)	1,589	473
Viger-Denonville (50%)	1,551	758
	3,140	1,231

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information

	Year ended December 31	
	2017	2016
Innergex's share of Adjusted EBITDA[1] of joint ventures:		
Umbata Falls (49%)	5,066	4,160
Viger-Denonville (50%)	4,549	4,225
	9,615	8,385

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information

Umbata Falls, L.P.

Summary Statements of Earnings and Comprehensive Income – Umbata Falls, L.P.

	Year ended December 31	
	2017	2016
Revenues	11,645	9,429
Operating and general and administrative expenses	1,307	938
Adjusted EBITDA[1]	10,338	8,491
Finance costs	2,392	2,507
Other net expenses (revenues)	23	(31)
Depreciation and amortization	4,016	4,017
Unrealized net gain on financial instruments	(2,056)	(526)
Net earnings and comprehensive income	5,963	2,524

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the year ended December 31, 2017, production was 125% of the LTA due to above-average water flows.

The increase in Adjusted EBITDA for the year ended December 31, 2017, is due mainly to higher production levels and revenues compared with the same period last year.

For the year ended December 31, 2017, Umbata Falls L.P. recorded net earnings and comprehensive income of $6.0 million, compared with $2.5 million for the same period last year. The increase reflects the higher revenues and higher unrealized net gain on financial instruments.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statements of Financial Position – Umbata Falls, L.P.

	As at	
	December 31, 2017	December 31, 2016
Current assets	3,550	2,090
Non-current assets	60,658	64,647
	64,208	66,737
Current liabilities	3,512	3,033
Non-current liabilities	40,924	46,173
Partners' equity	19,772	17,531
	64,208	66,737

As at December 31, 2017, the increase in partners' equity stems from the recognition of $6.0 million in net earnings and comprehensive income, partly offset by the $3.7 million distributions to the Corporation and its partner. To manage its exposure to the risk of increasing interest rates on its debt financing, Umbata Falls, L.P. uses a derivative financial instrument but does not own or issue any derivative financial instruments for speculation purposes. An amortizing interest-rate swap totaling $41.6 million used to hedge the interest rate on the Umbata Falls loan had a net negative value of $5.5 million at December 31, 2017 (negative value of $7.6 million at December 31, 2016).

Viger-Denonville, L.P.

Summary Statements of Earnings and Comprehensive Income – Viger-Denonville, L.P.

	Year ended December 31	
	2017	2016
Revenues	10,998	10,293
Operating and general and administrative expenses	1,899	1,844
Adjusted EBITDA[1]	9,099	8,449
Finance costs	3,466	3,635
Other net revenues	(40)	(30)
Depreciation and amortization	2,815	2,923
Unrealized net gain on financial instruments	(704)	(658)
Net earnings	3,562	2,579
Other comprehensive income	1,501	2
Total other comprehensive income	5,063	2,581

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the year ended December 31, 2017, production was 101% of the LTA due mainly to an average wind regime.

For the year ended December 31, 2017, the Adjusted EBITDA increased due mainly to higher revenues compared with last year.

For the year ended on December 31, 2017, the increase in net earnings compared with last year is due mainly to higher Adjusted EBITDA and lower finance costs.

For the year ended on December 31, 2017, the increase in other comprehensive income is attributable mainly to unrealized net gains on financial instruments.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statements of Financial Position – Viger-Denonville, L.P.

	As at	
	December 31, 2017	December 31, 2016
Current assets	3,005	2,249
Non-current assets	53,812	56,583
	56,817	58,832
Current liabilities	4,355	4,375
Non-current liabilities	49,920	54,223
Partners' equity	2,542	234
	56,817	58,832

As at December 31, 2017, the increase in partners' equity stems mainly from the recognition of $5.1 million in net earnings and other comprehensive income, partly offset by the $2.8 million in distributions to the Corporation and its partner. Viger-Denonville, L.P. uses a derivative financial instrument to manage its exposure to the risk of increasing interest rates on its debt financing and does not own or issue any derivative financial instruments for speculation purposes. An amortizing interest-rate swap totaling $49.3 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $3.3 million at December 31, 2017 (negative $5.5 million at December 31, 2016).

NON-WHOLLY OWNED SUBSIDIARIES

Summarized financial information regarding each of the Corporation's subsidiaries that has material non-controlling interests is set out below. Amounts are shown before intragroup eliminations.

Harrison Hydro Limited Partnership ("Harrison Hydro L.P.") and Its Subsidiaries

The Corporation owns a 50.01% interest in Harrison Hydro Limited Partnership, which has interests in six hydroelectric facilities: Douglas Creek, Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River.

Summary Statements of Earnings and Comprehensive Income – Harrison Hydro L.P.

	Year ended December 31	
	2017	2016
Revenues	50,891	60,039
Adjusted EBITDA[1]	36,847	48,437
Net (loss) earnings and comprehensive (loss) income	(6,798)	4,982
Net (loss) earnings and comprehensive (loss) income attributable to:		
Owners of the parent	(3,970)	1,919
Non-controlling interests	(2,828)	3,063
	(6,798)	4,982

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the year ended December 31, 2017, the net loss recorded is due mainly to lower production levels and revenues. Also, operating expenses were impacted by a $3.2 million aggregate payment related to water rights for 2011 and 2012 for the Harrison Hydro L.P. facilities, which were reassessed following the decision by the British Columbia Ministry of Forests, Lands and Natural Resource Operations to apply higher rental rates based on the facilities' combined production rather than apply lower rates for each facility based on its individual production, as had previously been the ministry's practice. The Corporation has filed an appeal of this decision with the Environmental Appeal Board. Since 2013, these facilities' water rights fees have been paid at the higher rates. A 49.99% portion of the water rights payment is allocated to the non-controlling interests.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statements of Financial Position – Harrison Hydro L.P.

	As at	
	December 31, 2017	December 31, 2016
Current assets	13,376	22,416
Non-current assets	601,105	615,937
	614,481	638,353
Current liabilities	17,163	17,847
Non-current liabilities	453,647	458,037
Equity attributable to owners	90,787	100,759
Non-controlling interests	52,884	61,710
	614,481	638,353

The decrease in equity attributable to owners and non-controlling interests is due mainly to a $12.0 million distribution to the Corporation and its partners and to the recognition of a comprehensive loss.

Creek Power Inc. and Its Subsidiaries

The Corporation owns a 66 2/3% interest in Creek Power Inc., which has interests in the Fitzsimmons Creek, Upper Lillooet River and Boulder Creek hydroelectric facilities. The Upper Lillooet River hydro facility began commercial operation on March 30, 2017, and the Boulder Creek hydro facility began commercial operation on May 16, 2017. For more information on these facilities, please refer to the "Developments in 2017" section of this MD&A.

Summary Statements of Earnings and Comprehensive Income – Creek Power Inc.

	Year ended December 31	
	2017	2016
Revenues	27,882	3,413
Adjusted EBITDA[1]	21,411	1,532
Net loss	(13,580)	(4,559)
Other comprehensive income	465	26
Total comprehensive loss	(13,115)	(4,533)
Net loss attributable to:		
Owners of the parent	(9,047)	(3,028)
Non-controlling interest	(4,533)	(1,531)
	(13,580)	(4,559)
Total comprehensive loss attributable to:		
Owners of the parent	(8,737)	(3,011)
Non-controlling interest	(4,378)	(1,522)
	(13,115)	(4,533)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the year ended December 31, 2017, total comprehensive loss reflects challenging post-commissioning activities currently being addressed at the Upper Lillooet River facility which impacted revenues. Finance costs and depreciation and amortization expenses were higher during the year following the commissioning of the facilities. The recognition of a net loss is attributable mainly to the recording of $11.2 million of preferred return payable to the Corporation on the $98.4 million preferred units, partly offset by higher revenues for the year. Excluding the preferred return, the net loss would have been $2.4 million.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statements of Financial Position – Creek Power Inc.

	As at	
	December 31, 2017	December 31, 2016
Current assets	36,422	82,759
Non-current assets	542,988	492,414
	579,410	575,173
Current liabilities	53,658	48,853
Non-current liabilities	618,205	605,658
Deficit attributable to owners	(65,388)	(56,651)
Non-controlling interest deficit	(27,065)	(22,687)
	579,410	575,173

The decrease in current assets is due mainly to the decrease in restricted cash, which was used to pay for ongoing construction costs, partly offset by cash cumulated and not distributed since the commissioning of the Upper Lillooet River and Boulder Creek facilities. The increase in non-current assets is due mainly to construction spending for the Upper Lillooet River and Boulder Creek projects. The increase in non-current liabilities is due to liabilities related to future ownership rights owned by First Nations for the Upper Lillooet River and Boulder Creek facilities.

Kwoiek Creek Resources Limited Partnership

The Corporation owns a 50.0% interest in Kwoiek Creek Resources Limited Partnership, which owns the Kwoiek Creek hydroelectric facility.

Summary Statements of Earnings and Comprehensive Income – Kwoiek Creek Resources Limited Partnership

	Year ended December 31	
	2017	2016
Revenues	19,016	19,840
Adjusted EBITDA[1]	15,234	15,519
Net loss and comprehensive loss	(890)	(704)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(445)	(352)
Non-controlling interest	(445)	(352)
	(890)	(704)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the year ended December 31, 2017, the decreases in revenues and Adjusted EBITDA are due mainly to production levels that were lower than for the same period last year. The recognition of a net loss is attributable mainly to the recording of a $4.2 million preferred return payable to the Corporation on the $39.8 million preferred units and the $3.7 million subordinated debt. Excluding these elements, net earnings would have been $3.7 million.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statements of Financial Position – Kwoiek Creek Resources Limited Partnership

	As at	
	December 31, 2017	December 31, 2016
Current assets	7,335	8,949
Non-current assets	172,223	175,049
	179,558	183,998
Current liabilities	7,919	9,964
Non-current liabilities	193,480	194,985
Deficit attributable to owners	(10,672)	(10,227)
Non-controlling interests deficit	(11,169)	(10,724)
	179,558	183,998

For the year ended December 31, 2017, the decrease in non-current assets in due mainly to the depreciation and amortization.

Mesgi'g Ugju's'n (MU) Wind Farm, L.P. ("Mesgi'g Ugju's'n")

The Corporation owns a 50% interest in Mesgi'g Ugju's'n (MU) Wind Farm, L.P., which owns the Mesgi'g Ugju's'n wind project. The Mesgi'g Ugju's'n wind farm began commercial operation on December 30, 2016.

Summary Statement of Earnings and Comprehensive Income – Mesgi'g Ugju's'n

	Year ended December 31	
	2017	2016
Revenues	51,845	1,024
Adjusted EBITDA[1]	46,219	945
Net earnings (loss)	21,825	(1,097)
Other comprehensive income (loss)	3,246	(1,643)
Total comprehensive income (loss)	25,071	(2,740)
Net earnings (loss) attributable to:		
Owners of the parent	15,795	(794)
Non-controlling interest	6,030	(303)
	21,825	(1,097)
Total comprehensive income (loss) attributable to:		
Owners of the parent	18,144	(1,955)
Non-controlling interest	6,927	(785)
	25,071	(2,740)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the year ended December 31, 2017, net earnings are due to revenues stemming from the Mesgi'g Ugju's'n facility being in operation despite challenging post-commissioning activities, partly offset by higher finance costs and amortization and depreciation expenses.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statement of Financial Position – Mesgi'g Ugju's'n

	As at	
	December 31, 2017	December 31, 2016
Current assets	21,727	64,843
Non-current assets	283,271	294,918
	304,998	359,761
Current liabilities	16,004	59,360
Non-current liabilities	247,867	264,582
Equity attributable to owners	44,826	44,986
Non-controlling interest deficit	(3,699)	(9,167)
	304,998	359,761

The decrease in current assets is attributable for the most part to the decrease in accounts receivable following the reimbursement of the Mesgi'g Ugju's'n substation, partly offset by higher restricted cash and short-term investments from the cash cumulated and not distributed since the commissioning of the Mesgi'g Ugju's'n facility. The decrease in non-current assets is due mainly to amortization and depreciation expenses.

The decrease in current liabilities is mainly due to the reimbursement of the Mesgi'g Ugju's'n substation loan, partly offset by the payables transferred from the non-current liabilities to the current liabilities.

Innergex Sainte-Marguerite, S.E.C. ("SM S.E.C.")

The Corporation owns 50.01% of the common units and all of the preferred units of SM S.E.C., which owns the Sainte-Marguerite hydroelectric facility.

Summary Statements of Earnings and Comprehensive Income – SM S.E.C.

	Year ended December 31	
	2017	2016
Revenues	12,755	10,666
Adjusted EBITDA[1]	10,507	8,148
Net loss and comprehensive loss	(2,104)	(4,289)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(1,052)	(2,145)
Non-controlling interest	(1,052)	(2,144)
	(2,104)	(4,289)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

The recognition of a net loss is attributable mainly to the recording of $4.6 million of preferred return payable to the Corporation on the $43.8 million preferred units, partly offset by higher revenues for the year. Excluding the preferred return, net earnings would have been $2.5 million.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statements of Financial Position – SM S.E.C.

	As at	
	December 31, 2017	December 31, 2016
Current assets	2,794	2,344
Non-current assets	129,614	132,351
	132,408	134,695
Current liabilities	8,085	8,654
Non-current liabilities	121,067	120,681
Equity attributable to owners	9,870	10,922
Non-controlling interests deficit	(6,614)	(5,562)
	132,408	134,695

For the year ended December 31, 2017, the decrease in non-current assets is due mainly to the depreciation and amortization. As at December 31, 2017, the decrease of equity attributable to owners and the increase in the non-controlling interest deficit is attributable to the recognition of a comprehensive loss during the year.

Innergex Europe (2015) Limited Partnership and Its Subsidiaries ("Innergex Europe")

The Corporation owns a 69.55% interest in Innergex Europe, which owns the Antoigné, Beaumont, Bois d'Anchat, Bois des Cholletz, Les Renardières, Longueval, Montjean, Plan Fleury, Porcien, Rougemont 1-2, Theil-Rabier, Vaite, Vallottes and Yonne wind facilities. For more information on Les Renardières, Plan Fleury and Rougemont-2, please refer to the "Developments in 2017" section of this MD&A.

On February 21, 2017, Innergex and RRMD completed the acquisition of the Yonne wind facility located in Northern France. The acquisition was realized through wholly owned foreign subsidiaries of Innergex Europe.

On May 24, 2017, Innergex and RRMD completed the acquisition of the Rougemont-1 and Vaite wind farms and the Rougemont-2 wind project located in Bourgogne-Franche-Comté in France. The acquisition was realized through wholly owned foreign subsidiaries of Innergex Europe.

On August 25, 2017, Innergex and RRMD completed the acquisition of the Les Renardières and Plan Fleury wind projects located in Champagne-Ardenne, France. The acquisition was realized through wholly owned foreign subsidiaries of Innergex Europe.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statements of Earnings and Comprehensive Income – Innergex Europe

	Year ended December 31, 2017	Period of 261 days ended December 31, 2016
Revenues	52,300	9,836
Adjusted EBITDA[1]	40,164	5,208
Net loss	(23,538)	(11,309)
Other comprehensive income (loss)	354	(799)
Total comprehensive loss	(23,184)	(12,108)
Net loss attributable to:		
Owners of the parent	(16,370)	(8,601)
Non-controlling interests	(7,168)	(2,708)
	(23,538)	(11,309)
Total comprehensive loss attributable to:		
Owners of the parent	(16,124)	(9,157)
Non-controlling interests	(7,060)	(2,951)
	(23,184)	(12,108)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the year ended December 31, 2017, production was 86% of the LTA, due mainly to the below-average wind regime in France. The net loss for the period is due mainly to low revenues resulting from the below-average production, higher finance costs and depreciation and amortization expenses. The expenses include $1.9 million of acquisition costs ($1.7 million in 2016), $5.0 million in interest payable to Desjardins on the $78.0 million debenture ($1.5 million on the $38.2 million debenture in 2016), a $11.5 million preferred return payable to Innergex on the $178.1 million preferred units ($4.3 million on the $87.2 million preferred units in 2016) and $0.1 million in interest payable to Innergex on a temporary bridge loan ($0.6 million in 2016). Excluding these items, the net loss would have been $5.1 million ($3.3 million in 2016). Expenses also include non-cash expenses such as depreciation and amortization of a total of $31.7 million ($9.8 million in 2016).

Summary Statements of Financial Position – Innergex Europe

	As at	
	December 31, 2017	December 31, 2016
Current assets	76,091	19,036
Non-current assets	967,260	325,310
	1,043,351	344,346
Current liabilities	119,935	32,475
Non-current liabilities	934,396	316,508
Deficit attributable to owners	(21,541)	(5,416)
Non-controlling interests	10,561	779
	1,043,351	344,346

The increase in all Financial Position items results from the recently acquired wind facilities in February, May and August 2017.

The excess in current liabilities over the current assets comes mainly from the interest payable to RRMD on the debenture and the preferred return payable to Innergex on the preferred units.

Entities excluded from the Corporation's control policies and procedures

The Rougemont 1-2, Vaite, Les Renardières and Plan Fleury figures are excluded from the Corporation's control policies and procedures, as stated in the "Establishment and Maintenance of DC&P and ICFR" section of this MD&A.

Summary financial information about the Rougemont 1-2, Vaite, Plan Fleury and Les Renardières is set out below:

(in thousands of Canadian dollars, except as noted and amounts per share)

Summary Statement of Earnings and Comprehensive (Loss) Income – Rougemont 1-2 and Vaite

	Period of 221 days ended December 31, 2017
Revenues	14,113
Adjusted EBITDA[1]	11,528
Net earnings	1,572
Other comprehensive income	46
Total comprehensive income	1,618

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Summary Statement of Financial Position – Rougemont 1-2 and Vaite

	As at December 31, 2017
Current assets	20,753
Non-current assets	345,562
	366,315
Current liabilities	30,696
Non-current liabilities	295,718
Equity	39,901
	366,315

Summary Statement of Earnings and Comprehensive Income – Plan Fleury and Les Renardières

	Period of 129 days ended December 31, 2017
Revenues	3,280
Adjusted EBITDA[1]	3,104
Net earnings	1,309
Other comprehensive income	7
Total comprehensive income	1,316

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Summary Statement of Financial Position – Plan Fleury and Les Renardières

	As at December 31, 2017
Current assets	26,542
Non-current assets	161,664
	188,206
Current liabilities	30,061
Non-current liabilities	117,297
Equity	40,848
	188,206

(in thousands of Canadian dollars, except as noted and amounts per share)

RELATED PARTY TRANSACTIONS

Related party transactions conducted in the normal course of operations are measured at fair value which is the amount established and agreed to by the related parties, unless specific requirements within IFRS require different treatment.

The Corporation's subsidiaries have entered into the following transactions with partners: Sainte Marguerite L.P.'s debenture to RRMD; Magpie's convertible debenture to the municipality; Innergex Europe (2015) Limited Partnership's debenture to RRMD; and Kwoiek Creek's loan to a partner (please refer to the "Notes to the Consolidated Financial Statements" for more information).

As of the closing of the Alterra Acquisition, the following transactions had occurred: (i) in 2011, Ross J. Beaty entered into a revolving credit facility with Alterra (the “Credit Facility”). The Credit Facility has a borrowing capacity amount of C$20.0 million and makes funds available to Alterra on a revolving basis at an interest rate of 8% per annum, compounded and payable monthly. In addition, a standby fee in the amount of 0.75% of the Credit Facility, and a drawdown fee in the amount of 1.5% of amounts advanced, are payable in cash. The Credit Facility matures on March 31, 2018. As at February 16, 2018, Alterra had borrowed C$17.3 million under the Credit Facility; and (ii) in October 2016, Ross J. Beaty loaned through a five-year term bond US$35.7 million to Alterra’s subsidiary Magma Energy Sweden A.B (the “Bond”). The Bond pays interest at 8.5% per annum with an upfront fee of 2% of the principal which was paid at closing of the financing. The Bond is collateralized by 15% of the outstanding shares in HS Orka.

NON-IFRS MEASURES

This MD&A has been prepared in accordance with IFRS. However, some measures referred to in this MD&A are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Innergex believes that these indicators are important, as they provide management and the reader with additional information about the Corporation's production and cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods. Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted EBITDA Proportionate, Adjusted Net Earnings, Free Cash Flow and Payout Ratio are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS.

References in this document to “Adjusted EBITDA” are to revenues less operating expenses, general and administrative expenses and prospective project expenses. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted EBITDA should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section of this MD&A for the reconciliation of Adjusted EBITDA.

References in this document to "Adjusted EBITDA Margin" are to Adjusted EBITDA divided by revenues. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance.

References in this document to "Adjusted EBITDA Proportionate" are to Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the joint ventures. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted EBITDA Proportionate should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Investments in Joint Ventures" section of this MD&A for the reconciliation of Adjusted EBITDA Proportionate.

References to "Adjusted Net Earnings" are to net earnings or losses of the Corporation, to which the following elements are added (subtracted): unrealized net (gain) loss on financial instruments; realized (gain) loss on financial instruments; income tax expense (recovery) related to the above items; and the share of unrealized net (gain) loss on derivative financial instruments of joint ventures, net of related tax. Innergex uses derivative financial instruments to hedge its exposure to various risks, such as interest rate and foreign exchange risks. Accounting for derivatives under International Accounting Standards requires that all derivatives are marked-to-market with changes in the mark-to-market of the derivatives for which hedge accounting is not applied being taken to the profit and loss account. The application of this accounting standard results in a significant amount of profit and loss volatility arising from the use of derivatives that are not designated for hedge accounting. The Adjusted Net Earnings of the Corporation aims to eliminate the impact of the mark-to-market rules on derivatives on the profit and loss of the Corporation. Innergex believes that the analysis and presentation of net earnings or loss on this basis enhances understanding of the Corporation's operating performance. Readers are cautioned that Adjusted Net Earnings should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section of this MD&A for the reconciliation of Adjusted Net Earnings.

References to “Free Cash Flow” are to cash flows from operating activities before changes in non-cash operating working capital items, less maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends declared and the portion of Free Cash Flow attributed to non-controlling interests, plus cash receipts by the Harrison Hydro L. P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their power purchase agreement, plus or minus other elements that are not representative of the Corporation's long-term cash generating capacity, such as transaction costs related to realized acquisitions (which are financed at the time of the acquisition), realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt or the exchange rate on equipment purchases. Innergex believes that presentation of this measure enhances the understanding of the Corporation's cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. Readers are cautioned that Free Cash Flow should not be construed as an alternative to cash flows from operating activities, as determined in accordance with IFRS. Please refer to the "Free Cash Flow and Payout Ratio" section of this MD&A for the reconciliation of Free Cash Flow.

References to “Payout Ratio” are to dividends declared on common shares divided by Free Cash Flow. Innergex believes that this is a measure of its ability to sustain current dividends and dividend increase as well as its ability to fund its growth.

This MD&A contains references to the Alterra Power Corp. acquisition. Gross Adjusted EBITDA, Net Adjusted EBITDA and Projected Revenues are not recognized under IFRS, have no standardized meaning prescribed by them and therefore may not be comparable to those presented by other issuers. Innergex believes that these indicators are important, as they provide management and the reader with additional information about cash generation capabilities and facilitates the comparison of results over different periods.

References in this document to "Gross Adjusted EBITDA" are to Projected Revenues less operating expenses, general and administrative expenses and cost of power (if applicable), Readers are cautioned that Gross Adjusted EBITDA should not be construed as an alternative to net earnings as determined in accordance with IFRS.

References in this document to "Net Adjusted EBITDA" corresponds to Gross Adjusted EBITDA multiplied by Innergex's ownership interest in each facility.

References to "Projected Revenues" are to expected gross production of a project multiplied by the price of the associated power purchase agreement, the projected merchant price of electricity or secured financial power hedge contract. In these contracts, any pricing mechanisms that stipulate price adjustments depending on merchant prices reflect management's current views and expectations, subject to change, of the merchant prices. (HS Orka Projected Revenues are calculated from total generation produced by HS Orka multiplied by a mix of long- and short-term industrial and retail contracts as well as revenue from hot and cold water sales and other revenues.)

FORWARD-LOOKING INFORMATION

To inform readers of the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws (“Forward-Looking Information”), including the Corporation's power production, prospective projects, successful development, construction and financing of the projects under construction and the advanced-stage prospective projects, estimates of recoverable geothermal energy resources, business strategy, future development and growth prospects, business integration, governance, business outlook, objectives, plans and strategic priorities, and other statements that are not historical facts. Forward-Looking Information can generally be identified by the use of words such as “approximately”, “may”, “will”, "could", “believes", “expects", “intends”, "should", “plans”, “potential”, "project", “anticipates”, “estimates”, “scheduled” or “forecasts”, or other comparable terminology that state that certain events will or will not occur. It represents the projections and expectations of the Corporation relating to future events or results as of the date of this MD&A.

Future-oriented financial information: Forward-Looking Information includes future-oriented financial information or financial outlook within the meaning of securities laws, such as expected production, projected revenues, projected Adjusted EBITDA, projected Adjusted EBITDA Proportionate, projected Free Cash Flow and estimated project costs, to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of the potential financial impact of the acquisitions, of the Corporation's ability to sustain current dividends and of its ability to fund its growth. Such information may not be appropriate for other purposes.

Assumptions: Forward-Looking Information is based on certain key assumptions made by the Corporation, including those concerning hydrology, wind regimes, geothermal resources and solar irradiation, performance of operating facilities, project performance, economic, financial and financial market conditions, the Corporation’s success in developing new facilities, expectations and assumptions concerning availability of capital resources.

Risks and Uncertainties: Forward-Looking Information involves risks and uncertainties that may cause actual results or performance to be materially different from those expressed, implied or presented by the Forward-Looking Information. These are referred to in the "Risk Factors" section of this Annual Information Form and include, without limitation: the ability of the Corporation to execute its strategy for building shareholder value; its ability to raise additional capital and the state of the capital markets; liquidity risks related to derivative financial instruments; variability in hydrology, geothermal resources, wind regimes and solar irradiation; delays and cost overruns in the design and construction of projects; the ability to secure new power purchase agreements or renew any power purchase agreement; fluctuation affecting prospective power prices; health, safety and environmental risks; uncertainties surrounding the development of new facilities; obtainment of permits; equipment failure or unexpected operations and maintenance activity; interest rate fluctuations and refinancing risk; financial leverage and restrictive covenants governing current and future indebtedness; the possibility that the Corporation may not declare or pay a dividend; potential undisclosed liabilities associated with the Alterra Acquisition; failure to realize the anticipated benefits of the Alterra Acquisition; integration of the Alterra Acquisition; changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; variability of installation performance and related penalties; the ability to attract new talent or to retain officers or key employees; litigation; performance of major counterparties; social acceptance of renewable energy projects; relationships with stakeholders; equipment supply; exposure to many different forms of taxation in various jurisdictions; changes in general economic conditions; regulatory and political risks; ability to secure appropriate land; reliance on PPAs; availability and reliability of transmission systems; foreign market growth and development risks; foreign exchange fluctuations; increases in water rental cost or changes to regulations applicable to water use; assessment of water, wind, geothermal and sun resources and associated electricity production; natural disasters and *force majeure*; cybersecurity; sufficiency of insurance coverage limits and exclusions; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; integration of the facilities and projects acquired and to be acquired; failure to realize the anticipated benefits of acquisitions; reliance on shared transmission and interconnection infrastructure and the fact that revenues from the Miller Creek facility will vary based on the spot price of electricity; risks related to U.S. production tax credits, changes in U.S. corporate tax rates and availability of tax equity financing; host country economic, social and political conditions; risk inherent to geothermal resources; aluminum price risks; geological occurrences, rockslides, avalanches or other occurrences outside the Corporation's control; adverse claims to property title; unknown liabilities; reliance on intellectual property and confidential agreements to protect our rights and confidential information.

Although the Corporation believes that the expectations and assumptions on which Forward-Looking Information is based are reasonable under the current circumstances, readers are cautioned not to rely unduly on this Forward-Looking Information as no assurance can be given that it will prove to be correct. Forward-Looking Information contained herein is made as at the date of this MD&A and the Corporation does not undertake any obligation to update or revise any Forward-Looking Information, whether as a result of events or circumstances occurring after the date hereof, unless so required by law.

There are also risks inherent to the Alterra Transaction, including incorrect assessments of the value of the other entity. There can be no assurance that the strategic, operational or financial benefits expected to result from the Alterra Transaction will be realized.

Forward-Looking Information in This MD&A

The following table outlines the Forward-Looking Information contained in this MD&A, which the Corporation considers important to better inform readers about its potential financial performance, together with the principal assumptions used to derive this information and the principal risks and uncertainties that could cause actual results to differ materially from this information.

Principal Assumptions	Principal Risks and Uncertainties
Expected production For each facility, the Corporation determines a long-term average annual level of electricity production ("LTA") over the expected life of the facility, based on engineers' studies that take into consideration a number of important factors: for hydroelectricity, the historically observed flows of the river, the operating head, the technology employed and the reserved aesthetic and ecological flows; for wind energy, the historical wind and meteorological conditions and turbine technology; for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation; and for geothermal power, the historical geothermal resources, natural depletion of geothermal resources over time, the technology used and the potential of energy loss to occur before delivery. Other factors taken into account include, without limitation, site topography, installed capacity, energy losses, operational features and maintenance. Although production will fluctuate from year to year, over an extended period it should approach the estimated long-term average. On a consolidated basis, the Corporation estimates the LTA by adding together the expected LTA of all the facilities in operation that it consolidates (excludes Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville, which are accounted for using the equity method).	Improper assessment of water, wind, sun and geothermal resources and associated electricity production Variability in hydrology, wind regimes, solar irradiation and geothermal resources Natural depletion of geothermal resources Equipment failure or unexpected operations and maintenance activity Natural disaster

Principal Assumptions	Principal Risks and Uncertainties
Projected revenues For each facility, expected annual revenues are estimated by multiplying the LTA by a price for electricity stipulated in the power purchase agreement secured with a public utility or other creditworthy counterparty. These agreements stipulate a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery, except for the Miller Creek hydroelectric facility, which receives a price based on a formula using the Platts Mid-C pricing indices, and the Horseshoe Bend hydroelectric facility, for which 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission. In most cases, power purchase agreements also contain an annual inflation adjustment based on a portion of the Consumer Price Index. On a consolidated basis, the Corporation estimates annual revenues by adding together the projected revenues of all the facilities in operation that it consolidates (excludes Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville, which are accounted for using the equity method).	Production levels below the LTA caused mainly by the risks and uncertainties mentioned above Unexpected seasonal variability in the production and delivery of electricity Lower-than-expected inflation rate Changes in the purchase price of electricity upon renewal of a PPA
Projected Adjusted EBITDA For each facility, the Corporation estimates annual operating earnings by subtracting from the estimated revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operations and maintenance expenditures, property taxes and royalties; these are predictable and relatively fixed, varying mainly with inflation (except for maintenance expenditures). On a consolidated basis, the Company estimates annual Adjusted EBITDA by adding together the projected operating earnings of all the facilities in operation that it consolidates (excludes Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville, which are accounted for using the equity method), from which it subtracts budgeted general and administrative expenses, comprised essentially of salaries and office expenses, and budgeted prospective project expenses, which are determined based on the number of prospective projects the Corporation chooses to develop and the resources required to do so.	Lower revenues caused mainly by the risks and uncertainties mentioned above Variability of facility performance and related penalties Unexpected maintenance expenditures
Projected Adjusted EBITDA Proportionate On a consolidated basis, the Company estimates annual Adjusted EBITDA Proportionate by adding to the projected Adjusted EBITDA Innergex's share of Adjusted EBITDA of the joint ventures (Dokie 1, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville).	Lower revenues caused mainly by the risks and uncertainties mentioned above Variability of facility performance and related penalties Unexpected maintenance expenditures
Estimated project costs, expected obtainment of permits, start of construction, work conducted and start of commercial operation for Development Projects or Prospective Projects For each development project, the Corporation provides an estimate of project costs based on its extensive experience as a developer, directly related incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for the projected costs provided by the engineering, procurement and construction ("EPC") contractor retained for the project. The Corporation provides indications regarding scheduling and construction progress for its Development Projects and indications regarding its Prospective Projects, based on its extensive experience as a developer.	Performance of counterparties, such as the EPC contractors Delays and cost overruns in the design and construction of projects Obtainment of permits Equipment supply Interest rate fluctuations and financing risk Relationships with stakeholders Regulatory and political risks Higher-than-expected inflation Natural disaster Outcome of insurance claims
Projected Free Cash Flow and intention to pay dividend quarterly The Corporation estimates Projected Free Cash Flow as projected cash flows from operating activities before changes in non-cash operating working capital items, less estimated maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends declared and the portion of Free Cash Flow attributed to non-controlling interests, plus cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their power purchase agreement, plus or minus other elements that are not representative of the Corporation's long-term cash generating capacity, such as transaction costs related to realized acquisitions (which are financed at the time of the acquisition), realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt or the exchange rate on equipment purchases. The Corporation estimates the annual dividend it intends to distribute based on the Corporation operating results, cash flows, financial conditions, debt covenants, long term growth prospects, solvency, test imposed under corporate law for declaration of dividends and other relevant factors.	Adjusted EBITDA below expectations caused mainly by the risks and uncertainties mentioned above and by higher prospective project expenses Projects costs above expectations caused mainly by the performance of counterparties and delays and cost overruns in the design and construction of projects Regulatory and political risk Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness Unexpected maintenance capital expenditures Possibility that the Corporation may not declare or pay a dividend
Intention to submit projects under requests for proposals The Corporation provides indications of its intention to submit projects under requests for proposals based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these requests for proposals.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs

Principal Assumptions	Principal Risks and Uncertainties
Alterra's Projected Revenues For each facility, expected annual revenues are estimated by multiplying the expected production by the price of the associated power purchase agreement or secured financial power hedge contract. Any pricing mechanisms in these contracts that stipulate price adjustment depending on merchant prices reflect management's current views and expectations, subject to change, of the merchant prices. HS Orka's Projected Revenues are calculated from the total generation produced by the HS Orka assets multiplied by a mix of long- and short-term industrial and retail contracts as well as revenue from hot and cold water sales and other revenues. Projected Revenues excludes revenue generated from purchased power subsequently resold. U.S. dollar and Icelandic króna figures are converted to Canadian dollars at the USD-CAD rate of 1.289 and USD-ISK rate of 105.	Production levels below the expected production caused mainly by the risks and uncertainties mentioned above Unexpected seasonal variability in the production and delivery of electricity Lower than expected inflation rate Change in the purchase price of electricity upon renewal of a PPA Negative change of merchant price of electricity Negative change of the currency exchange rates
Alterra's Projected Gross Adjusted EBITDA and Net Adjusted EBITDA For each facility, annual operating earnings are estimated by subtracting from the estimated Projected Revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operating and maintenance expenditures, property taxes and royalties; these are predictable and relatively fixed, varying mainly with inflation (except for maintenance expenditures) and the cost of power (if applicable).	Lower revenues caused mainly by the risks and uncertainties mentioned above Variability of facility performance and related penalties Unexpected maintenance expenditures

RISKS AND UNCERTAINTIES

The Corporation is exposed to various risks and uncertainties and has outlined below those that it considers material. Additional risks and uncertainties are discussed in the "Risk Factors" section of the Corporation's most recent *Annual Information Form* available on SEDAR at sedar.com. There may also exist additional risks and uncertainties that are not presently known to the Corporation or that are currently believed to be immaterial that may adversely affect the Corporation's business.

Ability of the Corporation to Execute Its Strategy for Building Shareholder Value
The Corporation's strategy for building shareholder value is to acquire or develop high-quality power production facilities that generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital, and to distribute a stable dividend. However, there is no certainty that the Corporation will be able to acquire or develop high-quality power production facilities at attractive prices to supplement its growth.

The successful execution of this strategy requires careful timing and business judgment, as well as the resources to complete the development of power generating facilities. The Corporation may underestimate the costs necessary to bring power generating facilities into commercial operation or may be unable to quickly and efficiently integrate new acquisitions into its existing operations.

Ability to Raise Additional Capital and the State of the Capital Market
Future development and construction of new facilities and the development of the Development Projects and the Prospective Projects and other capital expenditures will be financed out of cash generated from the Corporation's operating facilities, borrowing or the issuance and sale of additional equity. To the extent that external sources of capital, including issuance of additional securities of the Corporation, become limited or unavailable, the Corporation's ability to make necessary capital investments to construct or maintain existing or future facilities would be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion. There are numerous renewable energy projects to be constructed in the coming years that will result in competition for capital. In addition, payment of dividends may impair the Corporation's ability to finance its ongoing and future projects.

Furthermore, the Corporation's capital-raising efforts could involve the issuance and sale of additional Common Shares, or debt securities convertible into its Common Shares, which, depending on the price at which such shares or debt securities are issued or converted, could have a material dilutive effect on holders of the Corporation's Common Shares and adversely impact the trading price of the Corporation's Common Shares.

Liquidity Risks Related to Derivative Financial Instruments
Derivative financial instruments are entered into with major financial institutions and their effectiveness is dependent on the performance of these institutions. Failure by one of them to perform its obligations could involve a liquidity risk. Liquidity risks related to derivative financial instruments also include the settlement of bond forward contracts on their maturity dates and the early termination option included in some interest rate swap contracts and foreign exchange contracts. The Corporation uses derivative financial instruments to manage its exposure to the risk of an increase in interest rates on its debt financing, of foreign currency variation or of electricity market price variation. The Corporation does not own or issue financial instruments for speculation purposes.

Variability in Hydrology, Geothermal Resources, Wind Regimes and Solar Irradiation

The amount of energy generated by the Corporation's hydroelectric facilities depends on the availability of water flows. There is no certainty that the long-term availability of such resources will remain unchanged. The Corporation's revenues may be significantly affected by events that impact the hydrological conditions of the Corporation's hydroelectric project facilities such as low and high water flows within the watercourses on which the Corporation's hydroelectric facilities are located. In the event of severe flooding, the Corporation's hydroelectric facilities may be damaged. Geothermal resources by their nature deteriorate over time. There is no certainty that there will be sufficient geothermal fluids to maintain the resource or that generation of power will permit maintenance of the resource as presently anticipated. Similarly, the amount of energy generated by the Corporation's wind farms will depend upon the availability of wind, which is naturally variable. A reduced or increased amount of wind at the location of one of the wind farms over an extended period may reduce the production from such facility and may reduce the Corporation's revenues and profitability. Finally, the amount of energy to be generated by the Corporation's solar farm will depend on the availability of solar radiation, which is naturally variable. Lower solar irradiation levels at only Corporation's solar farm over an extended period may reduce the production from such facilities and the Corporation's revenues and profitability. Variability in hydrology, geothermal resources, wind regimes and solar irradiation and their predictability may also be affected by climate changes which may provoke unforeseen changes in the historical trends.

Risks Inherent in Geothermal Resources

Until a geothermal resource is actually accessed and tested by production wells, the temperature and composition of underground fluids must be considered estimates only. In addition, estimates as to the percentage of heat that can be expected to be recovered at the surface and the efficiency of converting the heat into electrical energy are subject to a number of assumptions including, but not limited to, resource base temperature, areal extent of the geothermal reservoir, thickness of the geothermal reservoir, percentage of resource recovery and the expected lifetime of the geothermal reservoir.

Delays and Cost Overruns in the Design and Construction of Projects

Delays and cost over-runs may occur in completing the construction of the Development Projects, and the development and construction of Prospective Projects and future projects that the Corporation will undertake. A number of factors which could cause such delays or cost over-runs include, without limitation, permitting delays, construction pricing escalation, changing engineering and design requirements, the performance of contractors, labour disruptions, adverse weather conditions and the availability of financing. Even when complete, a facility may not operate as planned due to design or manufacturing flaws, which may not all be covered by warranty. Mechanical breakdown could occur in equipment after the period of warranty has expired, resulting in loss of production as well as the cost of repair. In addition, if the Development Projects are not brought into commercial operation within the delay stipulated in their PPA, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related PPA.

Ability to Secure New Power Purchase Agreements or Renew Any Power Purchase Agreement

Securing new PPAs, which is a key component of the Corporation's growth strategy, is a risk factor in light of the competitive environment faced by the Corporation. The Corporation expects to continue to enter into PPAs for the sale of its power, which PPAs are mainly obtained through participation in competitive Requests for Proposals processes or bilateral negotiations. During these processes and negotiations, the Corporation faces competitors ranging from large utilities to small independent power producers, some of which have significantly greater financial and other resources than the Corporation. There is no assurance that the Corporation will be selected as power supplier following any particular Request for Proposals in the future that the Corporation will be successful in such negotiations or that existing PPAs will be renewed or will be renewed on equivalent terms and conditions upon the expiry of their respective terms.

Fluctuations Affecting Prospective Power Prices

If the Corporation is unable to secure PPAs or power hedges for its development assets, or maintain or renew PPAs for its producing assets or contract for the sale of 100% of generation, the Corporation may be forced to sell electrical power generated at market price. Further, most of the output at the Shannon wind farm is, and once completed the Flat Top wind farm will be, sold under a long-term power hedge agreement. All output not sold under the long-term power hedge agreement is subject to merchant prices. If the Corporation is unable to produce sufficient power to meet its contractual obligations under its PPAs, the Corporation will be forced to purchase third-party power at merchant prices. If the settlement point of the Corporation's long-term power hedge agreements differs from the point of interconnection, power sales pursuant to that power hedge are further subject to locational risk. This potential difference in pricing is referred to as a "basis differential". Depending on the specifics of the power hedge, a large basis differential could require the Corporation to purchase third-party power at merchant prices, or otherwise supplement the basis differential to the hedge provider. Power sales under power hedges are also required to be sold in blocks of hourly periods. If the Corporation's output within any given block is insufficient to meet its contractual commitments, it may be required to purchase third party power at merchant prices to meet its commitments. This potential risk is referred to as a "shape risk".

The market price of power in individual jurisdictions can be volatile and may be incapable of being controlled. If the price of electricity should drop significantly, in each of the cases described above, the economic prospects of the operational properties that rely, in whole or in part, on merchant prices, such as Shannon, Miller Creek or development properties in which the

Corporation has an interest, could be significantly reduced or rendered uneconomic. The Corporation expects that the Flat Top project will be subject to similar risks. A material reduction in such prices, or a non-material reduction in such prices coupled with the impact of the aggregate risks described above, could have a material adverse effect on the Corporation's financial condition, in particular.

Health, Safety and Environmental Risks
The ownership, construction and operation of the Corporation's power generation assets carry an inherent risk of liability related to worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licences, permits and other approvals, and potential civil liability. Compliance with health, safety and environmental laws (and any future changes) and the requirements of licences, permits and other approvals remain material to the Corporation's business. The Corporation has incurred and will continue to incur significant capital and operating expenditures to comply with health, safety and environmental laws and to obtain and comply with licences, permits and other approvals and to assess and manage its potential liability exposure. Nevertheless, the Corporation may become subject to government orders, investigations, inquiries or other proceedings (including civil claims) relating to health, safety and environmental matters. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licences, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures. As a consequence, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to its business and operations.

Uncertainties Surrounding the Development of New Facilities
The Corporation participates in the construction and development of new power generating facilities. These facilities have greater uncertainty surrounding future profitability than existing operating facilities with established track records. In certain cases, many factors affecting costs are not yet determined, such as land royalty payments, water royalties, or municipal taxes. The Corporation is in some cases required to advance funds and post-performance bonds during development of its new facilities. If some of these facilities are not completed or do not operate to the expected specifications, or unforeseen costs or taxes are incurred, the Corporation could be adversely affected.

Obtainment of Permits
The Corporation does not currently hold all the approvals, licences and permits required for the construction and operation of the Development Projects or the Prospective Projects, including environmental approvals and permits necessary to construct and operate the Development Projects or the Prospective Projects. The failure to obtain or delays in obtaining all necessary licences, approvals or permits, including renewals thereof or modifications thereto, could result in construction of the Development Projects or the Prospective Projects being delayed or not being completed or commenced. There can be no assurance that any one Prospective Project will result in any actual operating facility.

In addition, delays may occur in obtaining necessary government approvals required for future power projects.

From time to time, and to secure long lead times required for ordering equipment, the Corporation may place orders for equipment and make deposits thereon or advance projects prior to obtaining all requisite permits and licences. The Corporation only takes such actions where it reasonably believes that such licences or permits will be forthcoming in due course prior to the requirement to expend the full amount of the purchase price. However, any delay in permitting could adversely affect the Corporation.

Environmental permits to be issued regarding any of the Development Projects or the Prospective Projects may contain conditions that need to be satisfied prior to obtaining a PPA, to start construction, during construction and during and after the operation of the Development Projects. It is not possible to predict the conditions imposed by such permits or the cost of any mitigating measures required by such permits.

Equipment Failure or Unexpected Operations and Maintenance Activity
The Corporation's facilities are subject to the risk of equipment failure due to deterioration of the asset from use or age, latent defect and design or operator error, among other things. To the extent that a facility's equipment requires longer-than-forecast down times for maintenance and repair, or suffers disruptions of power generation for other reasons, the Corporation's business, operating results, financial condition or prospects could be adversely affected.

Interest Rate Fluctuations and Refinancing Risk
Interest rate fluctuations are of particular concern to a capital-intensive industry such as the electric power business. The Corporation faces interest rate and debt refinancing risk in respect of floating-rate bank credit facilities used for construction and long-term financings. The Corporation's ability to refinance debt on favourable terms is dependent on debt capital market conditions, which are inherently variable and difficult to predict.

Financial Leverage and Restrictive Covenants Governing Current and Future Indebtedness
The Corporation's and its subsidiaries' operations are subject to contractual restrictions contained in the instruments governing any of their current and future indebtedness. The degree to which the Corporation and its subsidiaries are leveraged could have important consequences to shareholders, including: (i) the Corporation's and its subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions or other project developments in the future may be limited; (ii) a significant portion of the Corporation's and its subsidiaries' cash flows from operations may be dedicated to the payment of the principal of and interest on their indebtedness, thereby reducing funds available for future operations; (iii) certain of the Corporation's and its subsidiaries' borrowings will be at variable rates of interest, which exposes the Corporation and its subsidiaries to the risk of increased interest rates; and (iv) the Corporation and its subsidiaries may be more vulnerable to economic downturns and be limited in their ability to withstand competitive pressures.

The Corporation and its subsidiaries are subject to operating and financial restrictions through covenants in certain loan, equity finance and security agreements. These restrictions prohibit or limit the Corporation's and its subsidiaries' ability to, among other things, incur additional debt, provide guarantees for indebtedness, create liens, dispose of assets, liquidate, dissolve, amalgamate, consolidate or effect any corporate or capital reorganization, make distributions or pay dividends, issue any equity interests and create subsidiaries. These restrictions may limit the Corporation's and its subsidiaries' ability to obtain additional financing, withstand downturns in the Corporation's and its subsidiaries' business and take advantage of business opportunities. Moreover, the Corporation and its subsidiaries may be required to seek additional debt or equity financing on terms that include more restrictive covenants, require repayment on an accelerated schedule or impose other obligations that limit the Corporation's or its subsidiaries' ability to grow the business, acquire assets or take other actions the Corporation or its subsidiaries might otherwise consider appropriate or desirable.

Possibility That the Corporation May Not Declare or Pay a Dividend
Holders of Common Shares, Series A Shares and Series C Shares do not have a right to dividends on such shares unless declared by the Board of Directors. The declaration of dividends is at the discretion of the Board of Directors even if the Corporation has sufficient funds, net of its liabilities, to pay such dividends.

The Corporation may not declare or pay a dividend if the Corporations' cash available for distribution is not sufficient or if there are reasonable grounds for believing that (i) the Corporation is, or would after the payment be, unable to pay its liabilities as they become due, or (ii) the realizable value of the Corporation's assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares.

Changes in Governmental Support to Increase Electricity to be Generated from Renewable Sources by Independent Power Producers
Development and growth of renewable energy is dependent on governmental support, policies and incentives. Many provincial governments have introduced portfolio standards, tax credits and other incentives to increase the portion of renewable energy in their electricity generation supply mix to reduce greenhouse gas emissions over time. There is a risk that governmental support providing incentives for renewable energy could change at any time and that additional increase in the procurement of renewable energy projects from independent power producers be reduced or suspended at any time. As a result, the Corporation may face reduced ability to develop its prospective projects and may suffer material write-offs of prospective projects.

Variability of Installation Performance and Related Penalties
The ability of the Corporation's facilities to generate the maximum amount of power which can be sold to Hydro-Québec, BC Hydro, the OPA, Électricité de France and other purchasers of electricity under PPAs is an important determinant of the Corporation's revenues. If one of the Corporation's facilities delivers less than the required quantity of electricity in a given contract year or is otherwise in default under its respective PPA, penalty payments may be payable to the relevant purchaser by the Corporation. The payment of any such penalties by the Corporation could adversely affect the revenues and profitability of the Corporation.

Exposure to Many Different Forms of Taxation in Various Jurisdictions
The Corporation is subject to many different forms of taxation in various jurisdictions throughout the world, including but not limited to, income tax, withholding tax, tax on capital, property tax, sales tax, transfer tax, social security and other payroll related taxes, which may be amended or may lead to disagreements with tax authorities regarding the application of tax law. Tax law and administration is extremely complex and often requires the Corporation to make subjective determinations. The computation of taxes involves many factors, including the interpretation of tax legislation in various jurisdictions in which the Corporation is or may become subject to tax assessments. The Corporation's estimate of tax related assets, liabilities, recoveries and expenses incorporates significant assumptions. These assumptions include, but are not limited to, the tax rates in various jurisdictions, the effect of tax treaties between jurisdictions and taxable income projections. To the extent that such assumptions differ from actual results, the Corporation may have to record additional tax expenses and liabilities, including interest and penalties.

Changes in General Economic Conditions
Most of the PPAs of the Corporation have fixed price adjusted annually for inflation on a CPI formula basis. If the inflation is lower than expected or if it decreases, the Corporation's expected revenues and projected adjusted EDITDA and free cash flow may be lower than expected or reduced which would respectively impact the payout ratio.

Reliance on various forms of PPAs
The power generated by the Corporation is mostly sold under long-term power purchase agreements and in some cases under power hedges and commercial and retail contracts. If, for any reason, any of the purchasers of power under such PPAs were unable or unwilling to fulfill their contractual obligations under the relevant PPA or if they refuse to accept delivery of power pursuant to the relevant PPA, the Corporation's business, operating results, financial condition or prospects could be adversely affected. If the Development Projects are not brought into commercial operation within the delay stipulated in their respective PPA or power hedges, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related PPA or power hedges.

Foreign Market Growth and Development Risks
The Corporation may, regarding any international expansion of its activities, face risks related to (i) its ability to effectively consummate future acquisitions, create new partnerships and develop, construct and operate projects in an unfamiliar regulatory and procurement market (ii) competing with more established competitors, (iii) foreign exchange fluctuations, (iv) lack of knowledge of foreign market and (v) changes in international and local taxation.

Foreign Exchange Fluctuations
The Corporation occasionally purchases equipment from foreign suppliers. As such, the Corporation may be exposed to changes in the Canadian dollar in relation to the foreign currency denominated equipment purchases. Our development work and operations in Canada, France, United States, Iceland and South America make us subject to foreign currency fluctuations.

Some of our revenue and costs are denominated in currencies other than the Canadian dollar. Foreign exchange fluctuations may impact our results as they are reported in Canadian dollars.

Our functional and reporting currency is the Canadian dollar. As such, our foreign investments, operations costs and assets will be exposed to net changes in currency exchange rates. Volatility in exchange rates could have an adverse effect on our business, financial condition and operating results.

Cybersecurity
The Corporation is dependent on various information technologies to carry out multiple business activities. A successful cyber intrusion, such as, and not limited to, unauthorized access, malicious software or other violations on the system that control generation and transmission at any of our offices or facilities could severely disrupt or otherwise affect business operations or diminish competitive advantages. These attacks on our information base systems through theft, alteration or destruction could generate unexpected 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. A breach of our cyber/data security measures could have a material adverse effect on the Corporation's business, operations, financial condition and operating results.

Failure to Realize the Anticipated Benefits of Acquisitions
The Corporation believes that the acquisitions recently completed and to be completed will provide benefits for the Corporation. However, there is a risk that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated by the management of the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation.

Risks related to U.S. Production Tax Credits, Changes in U.S. Corporate Tax Rates and Availability of Tax Equity Financing
The Corporation owns interest in projects for which on and off-site project activities are or were performed to qualify for United States renewable tax incentives (production tax credits, or "PTCs"). There can be no assurance that the projects will qualify for PTCs or, if they do, that they will qualify for full PTCs. There also can be no assurance that the PTCs will continue to be available. Any new tax rule, regulation or other guidance promulgated (as the same may be amended, updated or otherwise modified from time to time, including those amendments passed in late 2017) USA may jeopardize or otherwise impede the effectiveness of such on and off-site project activities qualifying such projects for the full value of PTCs.

Qualification of the projects for PTCs is critical to obtaining tax equity financing for wind projects. The inability to qualify the projects for PTCs, in whole or in part, would adversely affect the financing options for those projects. If the qualification of a project for PTCs is not successful, there may be a material impairment of the Corporation's investment in that project.

Other government actions could be taken that could, directly or indirectly, inhibit the Corporation's ability to raise tax equity financing. For example, following the tax reform enacted in late-2017, lower corporate tax rates in the United States may impact the amount of available tax equity investment for specific projects or generally in the market, impeding our ability to obtain sufficient amounts of tax equity investment on terms and at rates beneficial to the Corporation and its projects.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. During the reporting periods, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment, intangible assets, project development costs and goodwill, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives, effectiveness of hedging relationships and classification of structured entities. These estimates and assumptions are based on current market conditions, management's planned course of action and assumptions about future business and economic conditions. Changes in the underlying assumptions and estimates could have a material impact on the reported amounts. These estimates are reviewed periodically. If adjustments prove necessary, they are recognized in earnings in the period in which they are made.

Fair Value of Financial Instruments
Certain financial instruments, such as derivative financial instruments, are carried in the consolidated statements of financial position at fair value, with changes in fair value reflected in earnings unless hedge accounting is used in which case the changes are recognized in comprehensive income. Fair values of some financial instruments are estimated by using valuation techniques using several assumptions such as interest rate, credit spread and risk.

Useful Lives of Property, plant and equipment and Intangible assets
Property, plant and equipment and intangible assets represent a significant proportion of the Corporation's total assets. The Corporation reviews estimates of the useful lives of property, plant and equipment and Intangible assets on an annual basis and adjust depreciation on a prospective basis, if necessary.

Goodwill Impairment
The Corporation makes a number of estimates when calculating the recoverable amount of goodwill using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the numbers of years used in the cash flow model, and the discount rate.

Impairment of Property, plant and equipment, Intangible assets and Project development costs
The Corporation makes a number of estimates when calculating recoverable amount value using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the number of years used in the cash flow model, and the discount rate. The likelihood of being able to develop future projects is also assessed in regards of the competitive business environment and the willingness expressed by the governmental authorities of procuring additional sources of energy.

Business acquisition fair value
The Corporation makes a number of estimates when determining the acquisition date fair values of assets and liabilities acquired in a business acquisition. Fair values are estimated by using valuation techniques using several assumptions such as future production, earnings and expenses, interest and discount rates.

Structured entity
Based on the contractual arrangements between the Corporation and the other respective partner, the Corporation concluded that it has control over Kwoiek Creek Resources L.P and Mesgi'g Ugju's'n (MU) Wind Farm L.P.

Asset retirement obligations
The Corporation makes a number of estimates when calculating fair value of the amount of obligation using discounted rate. The obligation is measured at its present value using a current market-based, risk adjusted interest rate.

Hedging
The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

Income Taxes
The calculation of income taxes requires judgment in interpreting tax rules and regulations. The Corporation's tax filings are also subject to audits, the outcome of which could change the amount of current and deferred tax assets and liabilities. The Corporation believes that it has sufficient amounts accrued for outstanding tax matters based on the information that currently is available. Deferred tax assets and liabilities require management's judgment in determining the amounts to be recognized. In particular, judgment is required when assessing the timing of reversal of temporary differences to which future income tax rates are applied. Further, the amount of deferred tax assets, which is limited to the amount that is probable to be realized, is estimated with consideration given to the timing, sources and amounts of future taxable profit.

ACCOUNTING CHANGES

Revised IFRS affecting the reported financial performance and financial position in the current year

IAS 7 - Statement of Cash Flows

In January 2016, the IASB issued Disclosure Initiative (Amendments to IAS 7), which addressed that entities shall provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities. Those amendments must be applied for annual periods beginning on or after January 1, 2017 with early adoption permitted. The Corporation has disclosed the new requirements in Note 27 of the Notes to the Consolidated Financial Statements.

IAS 12 - Income Taxes

In January 2016, the IASB issued Amendments to IAS 12, which concluded that the diversity in practice around the recognition of a deferred tax asset that is related to a debt instrument measured at fair value is mainly attributable to uncertainty about the application of some of the principles in IAS 12. Those amendments must be applied for annual periods beginning on or after January 1, 2017. The new requirements on recognition of deferred tax assets were already followed by the Corporation. Accordingly, the Corporation has concluded that these amendments do not have any impact on its consolidated financial statements.

IFRS Issued but Not Yet Effective

IFRS 2 – Share-based Payments

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payments, clarifying how to account for certain types of share-based payment transactions. The amendments provide requirements on the accounting for: the effects of vesting and non-vesting conditions on the measurement of cash-settled share-based payments; share-based payment transactions with a net settlement feature for withholding tax obligations; and a modification to the terms and conditions of a share-based payment that changes the classification of the transaction from cash-settled to equity-settled. The amendments are effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. Employees of the Corporation took training courses in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. The Corporation has reviewed the amendments of this standard and has concluded that it will not have a significant impact on its consolidated financial statements.

IFRS 9 – Financial Instruments (2014)

In July 2014, the IASB issued the complete IFRS 9 (2014), Financial Instruments ("IFRS 9 (2014)"). IFRS 9 (2014) differs in some regards from IFRS 9 (2013) which the Corporation early adopted effective October 1, 2014. IFRS 9 (2014) includes updated guidance on the classification and measurement of financial assets. The final standard also amends the impairment model by introducing a new expected credit loss model for calculating impairment. The mandatory effective date of IFRS 9 (2014) is for annual periods beginning on or after January 1, 2018, and must be applied retrospectively with some exemptions. Early adoption is permitted. The Corporation has reviewed this standard and has concluded that it will not have a significant impact on its consolidated financial statements.

IFRS 15 – Revenue from Contracts with Customers

In May 2014, IASB issued IFRS 15 – Revenue from Contracts with Customers (“IFRS 15”). This standard replaces IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers, and SIC-31 Revenue-Barter Transactions Involving Advertising Services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2018, with early adoption permitted. The Corporation has reviewed this standard and has concluded that it will not have a significant impact on its consolidated financial statements.

IFRS 16 – Leases (IFRS 16)

On January 13, 2016, the IASB issued IFRS 16 that provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. It supersedes IAS 17 Leases and its associated interpretive guidance. Significant changes were made to lessee accounting with the distinction between operating and finance leases removed and assets and liabilities recognized in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). In contrast, IFRS 16 does not include significant changes to the requirements for lessors. IFRS 16 is effective January 1, 2019, with earlier application permitted. Employees of the Corporation took training courses in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. Identification of the leases to which this standard might apply has begun.

ESTABLISHMENT AND MAINTENANCE OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

In accordance with Regulation 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings, the President and Chief Executive Officer and the Chief Financial Officer of the Corporation have designed, or caused to be designed under their supervision:

- Disclosure controls and procedures (“DC&P”) to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the President and Chief Executive Officer and the Chief Financial Officer by others, particularly during the period in which the annual filings are being prepared; and (ii) the information required to be disclosed by the Corporation in its annual filings, interim filings and other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.
- Internal control over financial reporting (“ICFR”) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The President and Chief Executive Officer and the Chief Financial Officer of the Corporation have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's DC&P and ICFR as at December 31, 2017, and have concluded that they were effective at the financial year end. There were no significant weakness relating to the design and operation of DC&P and no material weaknesses relating to the design and operation of ICFR at the financial year end. During the period beginning on October 1, 2017 and ended on December 31, 2017, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

They have also limited the scope of the Corporation's design of DC&P and ICFR to exclude the controls, policies and procedures of Energies du Plateau Central (Rougemont-1), Energies du Plateau Central 2 (Rougemont-2), Energie du Rechet (Vaite), Éole de Plan Fleury and Les Renardières (collectively "entities excluded from the Corporation's control policies and procedures"). The evaluation of the design and the operating effectiveness of the DC&P and ICFR for these entities will be completed in the 12 months following their dates of acquisition. A summary of the financial information about the entities excluded is presented in the "Non-wholly Owned Subsidiaries" section of this MD&A.

SUBSEQUENT EVENTS

Acquisition of Alterra Power Corp.

On February 6, 2018, Innergex announced the completion of the acquisition of Alterra by way of an arrangement agreement pursuant to which Innergex acquired all of the issued and outstanding common shares of Alterra for an aggregate consideration of $1.1 billion, including the assumption of Alterra's debt (the "Transaction"). Pursuant to the Transaction, Alterra shareholders had the right to elect to receive either $8.25 in cash (“Cash Alternative”) or 0.5563 Innergex common shares (“Share Alternative”) for each Alterra common share, subject in each case to the pro-ration, such that the aggregate consideration paid to all Alterra shareholders consisted of approximately 25% in cash and 75% in Innergex common shares.

The Innergex common shares that were issuable to Alterra shareholders with the transaction represent an ownership of approximately 18% of the combined corporation. One member of the Board of Directors of Alterra joined the Board of Directors of Innergex at the closing of the Transaction.

Support from la Caisse de dépôt et placement du Québec

Concurrently with the closing of the Alterra acquisition, Innergex closed a $150 million subordinated unsecured 5-year term loan at a 5.13% interest rate with la Caisse de dépôt et placement du Québec.

Increase to the revolving credit facilities

On February 6, 2018, the Corporation announced that it had increased its revolving credit facilities by $225 million to $700 million and added a new lender to the syndicate of lenders. The maturity of the revolving credit facilities remains December 2022.

Decision rendered on water rights

On January 14, 2014, Harrison Hydro Project Inc., Fire Creek Project Limited Partnership, Lamont Creek Project Limited Partnership, Stokke Creek Project Limited Partnership, Tipella Creek Project Limited Partnership and Upper Stave Project Limited Partnership (the "Appellants") filed appeals with the Environmental Appeal Board challenging a determination by the Comptroller of the Water Rights respecting the water rental rates to be charged under the Water Act R.S.B.C. 1996, c. 483 in respect of the Fire Creek Facility, Lamont Creek Facility, Stokke Creek Facility, Tipella Creek Facility and Upper Stave River Facility. On December 8, 2015, the Environmental Appeal Board Decision issued its decision rejecting the appeal. On January 20, 2016, an application for judicial review was filed to the British Columbia Supreme Court ("BCSC"). On February 27, 2017, the BCSC declined to set aside the Environmental Appeal Board Decision. On March 21, 2017, the Appellants filed an appeal of the BCSC decision and on February 8, 2018, in a split decision, the British Columbia Court of Appeal refused to set aside the BCSC decision. The Appellants are currently analysing the possibility of filing a petition for permission to appeal to the Supreme Court of Canada. The outcome of the judicial review could affect the expenses of these entities on an annual basis going forward which would represent an approximately $1.6 million aggregate increase for water rights. The amount for such potential increase water rights rentals was included in the years 2013, 2014, 2015 and 2016 results of the Corporation, which owns a 50.0024% indirect interest in those facilities.

Responsibility for Financial Reporting

The consolidated financial statements of Innergex Renewable Energy Inc. (the “Corporation”) accompanying this annual report and all of the information herein concerning the Corporation are the responsibility of Management.

These consolidated financial statements were prepared by Management in accordance with **International Financial Reporting Standards (“IFRS”)** by applying the detailed accounting policies set out in the notes to the consolidated financial statements. Management is of the opinion that the consolidated financial statements were prepared based on reasonable criteria and using justifiable and reasonable estimates. The Corporation's financial information, presented elsewhere in the annual report, is consistent with what is presented in the consolidated financial statements.

Management maintains efficient and high-quality internal accounting and management control systems while ensuring that costs are reasonable. These systems provide assurance that the financial information is relevant, accurate and reliable, and that the Corporation's assets are correctly accounted for and adequately safeguarded.

The Board of Directors of the Corporation is responsible for ensuring that Management fulfils its financial reporting responsibilities. In addition, the Board of Directors is ultimately responsible for reviewing and approving the Corporation's consolidated financial statements. The Board of Directors fulfils this responsibility through its Audit Committee.

The Audit Committee is appointed by the Board of Directors and all of its members are external non-related Directors.

The Audit Committee meets with Management and the independent auditor for the purposes of discussing internal controls relating to the financial reporting process, audit of financial information and other financial issues, and to make sure that each party is properly fulfilling its responsibilities. In addition, the Audit Committee reviews the annual report, the consolidated financial statements and the independent auditor's report. The Audit Committee submits its finding to the Board of Directors for review and for approval of the consolidated financial statements prior to their presentation to the shareholders. The Audit Committee also determines whether to retain the services of independent auditor and to renew their mandate, which is subject to Board review and shareholders' approval.

These consolidated financial statements were approved by the Corporation's Board of Directors. The Corporation's consolidated financial statements were audited by its independent auditor, Deloitte LLP, in accordance with **Canadian generally accepted auditing standards** and on the shareholders' behalf. Deloitte LLP enjoy full and unrestricted access to the Audit Committee.

[s] Michel Letellier
Michel Letellier, MBA
President and Chief Executive Officer

[s] Jean Perron
Jean Perron, CPA, CA
Chief Financial Officer

Innergex Renewable Energy Inc.

Longueuil, Canada, February 21, 2018

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of
Innergex Renewable Energy Inc.

We have audited the accompanying consolidated financial statements of Innergex Renewable Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016 and the consolidated statements of earnings, consolidated statements of comprehensive income (loss), consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Innergex Renewable Energy Inc. as at December 31, 2017 and December 31, 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

[s] Deloitte LLP[1]

Montreal, Quebec
February 21, 2018

[1] CPA auditor, CA, public accountancy permit No. A111405

CONSOLIDATED STATEMENTS OF EARNINGS

	Notes	Year ended December 31 2017	2016
Revenues		400,263	292,785
Expenses			
Operating	6	71,672	51,469
General and administrative		17,806	15,045
Prospective projects		12,057	10,288
Earnings before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on financial instruments		298,728	215,983
Finance costs	7	146,766	95,254
Other net expenses	8	2,453	265
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments		149,509	120,464
Depreciation	6,18	92,762	61,722
Amortization	6,19	36,667	28,581
Share of earnings of joint ventures	9	(4,638)	(2,526)
Unrealized net gain on financial instruments	10	(2,245)	(4,292)
Earnings before income taxes		26,963	36,979
Income taxes expenses			
Current	11	4,141	2,970
Deferred	11	3,154	1,966
		7,295	4,936
Net earnings		19,668	32,043
Net earnings attributable to:			
Owners of the parent		30,007	35,963
Non-controlling interests	28	(10,339)	(3,920)
		19,668	32,043
Weighted average number of common shares outstanding (in 000s)	12	108,427	106,883
Basic net earnings per share ($)	12	0.22	0.28
Diluted weighted average number of common shares outstanding (in 000s)	12	109,247	107,762
Diluted net earnings per share ($)	12	0.22	0.28

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Notes	Year ended December 31 2017	2016
Net earnings		19,668	32,043
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:	26		
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries		27	(872)
Related deferred tax		(60)	91
Foreign exchange gain on the designated hedges on the investments in self-sustaining foreign subsidiaries		69	296
Related deferred tax		147	(17)
Change in fair value of hedging instruments		15,047	408
Related deferred tax		(4,172)	(74)
Share of change in fair value of hedging instruments of joint venture		815	1
Related deferred tax		(201)	—
Share of non-controlling interests in:			
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries		320	(253)
Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries		(323)	9
Change in fair value of hedging instruments		1,260	(55)
Related deferred tax		(98)	14
Other comprehensive income (loss)		12,831	(452)
Total comprehensive income		32,499	31,591
Other comprehensive income (loss) attributable to:			
Owners of the parent		11,672	(167)
Non-controlling interests		1,159	(285)
		12,831	(452)
Total comprehensive income attributable to:			
Owners of the parent		41,679	35,796
Non-controlling interests		(9,180)	(4,205)
		32,499	31,591

The accompanying notes are an integral part of these audited consolidated financial statements.

(in thousands of Canadian dollars, except as noted and amounts per share)

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	December 31, 2017	December 31, 2016
ASSETS			
Current assets			
Cash and cash equivalents		61,914	56,227
Restricted cash and short-term investments	15	58,676	89,742
Accounts receivable	16	87,500	98,847
Derivative financial instruments	10	5,416	1,527
Prepaid and others		8,104	5,886
		221,610	252,229
Non-current assets			
Reserve accounts	17	49,970	49,489
Property, plant and equipment	18	3,188,238	2,700,007
Intangible assets	19	654,081	544,865
Investments in joint ventures	9	11,011	8,758
Derivative financial instruments	10	9,558	8,117
Deferred tax assets	11	11,873	11,849
Goodwill	20	38,580	8,269
Other long-term assets		5,535	20,621
		4,190,456	3,604,204

The accompanying notes are an integral part of these audited consolidated financial statements.

(in thousands of Canadian dollars, except as noted and amounts per share)

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	December 31, 2017	December 31, 2016
LIABILITIES			
Current liabilities			
Dividends payable to shareholders		19,406	18,795
Accounts payable and other payables	21	91,032	85,850
Income tax payable	11	3,282	1,292
Derivative financial instruments	10	22,749	14,541
Current portion of long-term debt	22	109,875	99,397
Current portion of other liabilities	23	500	495
		246,844	220,370
Non-current liabilities			
Derivative financial instruments	10	54,494	55,194
Accrual for acquisition of long-term assets		—	37,401
Long-term debt	22	3,047,583	2,507,236
Other liabilities	23	79,507	26,966
Liability portion of convertible debentures	24	96,246	94,840
Deferred tax liabilities	11	215,593	176,965
		3,740,267	3,118,972
SHAREHOLDERS' EQUITY			
Common share capital	25 a)	2,867	162,862
Contributed surplus from reduction of capital on common shares	25 b)	939,047	775,413
Preferred shares	25 c)	131,069	131,069
Share-based payment	25 d)	1,713	2,199
Equity portion of convertible debentures		1,877	1,877
Deficit		(651,233)	(601,157)
Accumulated other comprehensive income (loss)	26	9,929	(1,743)
Equity attributable to owners		435,269	470,520
Non-controlling interests	28	14,920	14,712
Total shareholders' equity		450,189	485,232
		4,190,456	3,604,204

The accompanying notes are an integral part of these audited consolidated financial statements.

(in thousands of Canadian dollars, except as noted and amounts per share)

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Equity attributable to owners									
Year ended December 31, 2017	Common shares capital account	Contributed surplus from reduction of capital on common shares	Preferred shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive (loss) income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2017	162,862	775,413	131,069	2,199	1,877	(601,157)	(1,743)	470,520	14,712	485,232
Net earnings (loss)						30,007		30,007	(10,339)	19,668
Other items of comprehensive income							11,672	11,672	1,159	12,831
Total comprehensive income (loss)	—	—	—	—	—	30,007	11,672	41,679	(9,180)	32,499
Common shares issued through dividend reinvestment plan	5,135							5,135		5,135
Reduction of capital on common shares (Note 25b)	(166,460)	166,460						—		—
Share buyback of common shares	(1)	(471)				(305)		(777)		(777)
Share-based payment				99				99		99
Common shares options exercised (Note 25d)	1,335			(585)		(1,234)		(484)		(484)
Shares purchased - PSP plan	(4)	(2,355)				(981)		(3,340)		(3,340)
Distributions to non-controlling interests								—	(7,458)	(7,458)
Investments from non-controlling interests								—	16,846	16,846
Dividends declared on common shares						(71,621)		(71,621)		(71,621)
Dividends declared on preferred shares						(5,942)		(5,942)		(5,942)
Balance December 31, 2017	2,867	939,047	131,069	1,713	1,877	(651,233)	9,929	435,269	14,920	450,189

The accompanying notes are an integral part of these audited consolidated financial statements.

(in thousands of Canadian dollars, except as noted and amounts per share)

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

Year ended December 31, 2016	Equity attributable to owners									
	Common shares capital account	Contributed surplus from reduction of capital on common shares	Preferred shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive loss	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2016	108,541	775,413	131,069	2,174	1,877	(567,848)	(1,576)	449,650	21,907	471,557
Net earnings (loss)						35,963		35,963	(3,920)	32,043
Other items of comprehensive loss							(167)	(167)	(285)	(452)
Total comprehensive income (loss)	—	—	—	—	—	35,963	(167)	35,796	(4,205)	31,591
Common shares issued on April 15, 2016: private placement	50,000							50,000		50,000
Common shares issued through dividend reinvestment plan	3,209							3,209		3,209
Share-based payment				103				103		103
Common shares options exercised	1,112			(78)				1,034		1,034
Distributions to non-controlling interests								—	(7,388)	(7,388)
Investments from non-controlling interests						5,194		5,194	4,398	9,592
Dividends declared on common shares						(68,524)		(68,524)		(68,524)
Dividends declared on preferred shares						(5,942)		(5,942)		(5,942)
Balance December 31, 2016	162,862	775,413	131,069	2,199	1,877	(601,157)	(1,743)	470,520	14,712	485,232

The accompanying notes are an integral part of these audited consolidated financial statements.

(in thousands of Canadian dollars, except as noted and amounts per share)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Notes	Year ended December 31 2017	2016
OPERATING ACTIVITIES			
Net earnings		19,668	32,043
Items not affecting cash:			
Depreciation	18	92,762	61,722
Amortization	19	36,667	28,581
Share of earnings of joint ventures	9	(4,638)	(2,526)
Unrealized net gain on financial instruments	10	(2,245)	(4,292)
Inflation compensation interest	7	3,910	4,207
Amortization of financing fees	7	2,980	1,194
Accretion of long-term debt and convertible debentures	7	1,404	1,442
Accretion expenses on other liabilities	7	1,664	551
Share-based payment		(385)	103
Deferred income taxes		3,154	1,966
Others		607	(130)
Interest on long-term debt and convertible debentures	7	134,420	86,687
Interest paid		(125,825)	(81,739)
(Gain) loss on contingent considerations	8	(881)	800
Distributions received from joint ventures		3,201	3,147
Current income tax expense		4,141	2,970
Net income taxes paid		(2,583)	(2,893)
Effect of exchange rate fluctuations		648	(638)
		168,669	133,195
Changes in non-cash operating working capital items	27	23,782	(56,442)
		192,451	76,753
FINANCING ACTIVITIES			
Dividends paid on common shares		(65,875)	(64,116)
Dividends paid on preferred shares		(5,942)	(6,237)
Distributions to non-controlling interests		(7,458)	(7,388)
Investments from non-controlling interests	28	16,842	9,565
Increase of long-term debt		668,856	872,247
Repayment of long-term debt		(576,187)	(657,207)
Payment of deferred financing costs		(1,161)	(2,680)
Payment of other liabilities	23	(246)	—
Payment for buyback of common shares		(4,119)	—
Proceeds from issuance of common shares	25	—	50,000
Proceeds from exercise of share options	25 d)	—	1,034
		24,710	195,218

The accompanying notes are an integral part of these audited consolidated financial statements.

(in thousands of Canadian dollars, except as noted and amounts per share)

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Year ended December 31	
		2017	2016
	Notes		
INVESTING ACTIVITIES			
Cash acquired on business acquisitions	5	5,335	11,998
Business acquisitions	5	(152,797)	(125,493)
Decrease of restricted cash and short-term investments		70,203	222,978
Net funds (invested into) withdrawn from the reserve accounts	17	(85)	1,610
Additions to property, plant and equipment		(135,656)	(351,258)
Investments in joint ventures		—	(50)
Reductions of (additions to) other long-term assets		1,020	(14,740)
Proceeds from disposal of property, plant and equipment		24	—
		(211,956)	(254,955)
Effects of exchange rate changes on cash and cash equivalents		482	(1,452)
Net increase in cash and cash equivalents		5,687	15,564
Cash and cash equivalents, beginning of period		56,227	40,663
Cash and cash equivalents, end of period		61,914	56,227
Cash and cash equivalents is comprised of:			
Cash		60,695	55,489
Short-term investments		1,219	738
		61,914	56,227

Additional information is presented in Note 27.

The accompanying notes are an integral part of these audited consolidated financial statements.

(in thousands of Canadian dollars, except as noted and amounts per share)

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. (“Innergex” or the “Corporation”) was incorporated under the *Canada Business Corporation Act* on October 25, 2002. The Corporation is a developer, owner and operator of renewable power-generating facilities, essentially focused on the hydroelectric, wind power and solar photovoltaic sectors. The head office of the Corporation is located at 1225 St-Charles Street West, 10th floor, Longueuil, Qc, J4K 0B9, Canada.

These consolidated financial statements were approved by the Board of Directors on February 21, 2018.

These consolidated financial statements have been prepared in accordance with the accounting policies described in Note 3.

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

These consolidated financial statements have been prepared using accounting policies consistent with International Financial Reporting Standards (“IFRS”).

The consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments that are measured at fair values as described in the significant accounting policies. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

2. APPLICATION OF IFRS

2.1 Revised IFRS affecting the reported financial performance and financial position in the current year

IAS 7 - Statement of Cash Flows

In January 2016, the IASB issued Disclosure Initiative (Amendments to IAS 7), which addressed that entities shall provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities. Those amendments must be applied for annual periods beginning on or after January 1, 2017 with early adoption permitted. The Corporation has disclosed the new requirements in Note 27.

IAS 12 - Income Taxes

In January 2016, the IASB issued Amendments to IAS 12, which concluded that the diversity in practice around the recognition of a deferred tax asset that is related to a debt instrument measured at fair value is mainly attributable to uncertainty about the application of some of the principles in IAS 12. Those amendments must be applied for annual periods beginning on or after January 1, 2017. The new requirements on recognition of deferred tax assets were already followed by the Corporation. Accordingly, the Corporation has concluded that these amendments do not have any impact on its consolidated financial statements.

2.2 IFRS issued but not yet effective

IFRS 2- Share-based Payments

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payments, clarifying how to account for certain types of share-based payment transactions. The amendments provide requirements on the accounting for: the effects of vesting and non-vesting conditions on the measurement of cash-settled share-based payments; share-based payment transactions with a net settlement feature for withholding tax obligations; and a modification to the terms and conditions of a share-based payment that changes the classification of the transaction from cash-settled to equity-settled. The amendments are effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. Employees of the Corporation took training courses in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. The Corporation has reviewed the amendments of this standard and has concluded that it will not have a significant impact on its consolidated financial statements.

IFRS 9 - Financial Instruments (2014)

In July 2014, the IASB issued the complete IFRS 9 (2014), Financial Instruments ("IFRS 9 (2014)"). IFRS 9 (2014) differs in some regards from IFRS 9 (2013) which the Corporation early adopted effective October 1, 2014. IFRS 9 (2014) includes updated guidance on the classification and measurement of financial assets. The final standard also amends the impairment model by introducing a new expected credit loss model for calculating impairment. The mandatory effective date of IFRS 9 (2014) is for annual periods beginning on or after January 1, 2018, and must be applied retrospectively with some exemptions. Early adoption is permitted. The Corporation has reviewed this standard and has concluded that it will not have a significant impact on its consolidated financial statements.

IFRS 15- Revenue from Contracts with Customers

In May 2014, IASB issued IFRS 15 – Revenue from Contracts with Customers ("IFRS 15"). This standard replaces IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers, and SIC-31 Revenue-Barter Transactions Involving Advertising Services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2018, with early adoption permitted. The Corporation has reviewed this standard and has concluded that it will not have a significant impact on its consolidated financial statements.

IFRS 16 Leases (IFRS 16)

On January 13, 2016, the IASB issued IFRS 16 that provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. It supersedes IAS 17 Leases and its associated interpretive guidance. Significant changes were made to lessee accounting with the distinction between operating and finance leases removed and assets and liabilities recognized in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). In contrast, IFRS 16 does not include significant changes to the requirements for lessors. IFRS 16 is effective January 1, 2019, with earlier application permitted. Employees of the Corporation took training courses in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. Identification of the leases to which this standard might apply has begun.

3. SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

The consolidated financial statements include the accounts of the Corporation, and the subsidiaries that it controls. Control exists where the Corporation has the power over the subsidiary, where the Corporation is exposed or has rights to variable returns from its involvement with the subsidiary and where the Corporation has the ability to use its power to affect its returns. Subsidiaries that the Corporation controls are consolidated from the effective date of acquisition up to the effective date of disposal or loss of control.

Details of the Corporation's significant subsidiaries at the end of the reporting period are set out below.

Name of subsidiaries	Principal activity	Place of creation and operation	Proportion of ownership interest and voting rights held by the Corporation
Harrison Hydro L.P. and its subsidiaries	Own and operate hydroelectric facilities	Canada	50.01%
Creek Power Inc. and its subsidiaries	Own and operate hydroelectric facilities	Canada	66.67%
Kwoiek Creek Resources L.P. [1]	Own and operate a hydroelectric facility	Canada	50.00%
Ashlu Creek Investments Limited Partnership	Own and operate a hydroelectric facility	Canada	100.00%
Innergex Inc.	Own and operate hydroelectric facilities	Canada	100.00%
Big Silver Creek Power Limited Partnership	Own and operate a hydroelectric facility	Canada	100.00%
Innergex Sainte-Marguerite S.E.C.	Own and operate a hydroelectric facility	Canada	50.01%
Tretheway Creek Power Limited Partnership	Own and operate a hydroelectric facility	Canada	100.00%
Mesgi'g Ugju's'n (MU) Wind Farm L.P. [2]	Own and operate a wind facility	Canada	50.00%
Innergex GM, L.P. [(3)]	Own and operate a wind facility	Canada	100.00%
Stardale Solar LP	Own and operate a solar facility	Canada	100.00%
Innergex Europe (2015) Limited Partnership and its subsidiaries	Own and operate wind facilities	Canada/Europe	69.55%

1. The Corporation owns more than 50% of the economic interest in Kwoiek Creek Resources L.P.
2. The Corporation owns more than 50% of the economic interest in Mesgi'g Ugju's'n (MU) Wind Farm L.P.
3. The Corporation owns through the Limited Partnership a 38% ownership interest in the assets, liabilities, revenues and expenses and 50% voting rights of the joint operations.

Investments in joint ventures

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the joint arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

The results and assets and liabilities of joint ventures are incorporated in these consolidated financial statements using the equity method of accounting. Under the equity method, an investment in a joint venture is initially recognized in the consolidated statement of financial position at cost and adjusted thereafter to recognize the Corporation's share of the profit or loss and other comprehensive income of the joint venture. When the Corporation's share of losses of a joint venture exceeds the Corporation's interest in that joint venture (which includes any long-term interest that, in substance, forms part of the Corporation's net investment in the joint venture), the Corporation discontinues recognizing its share of further losses. Additional losses are recognized only to the extent that the Corporation has incurred legal or constructive obligations or made payments on behalf of the joint venture.

(in thousands of Canadian dollars, except as noted and amounts per share)

An investment is accounted for using the equity method from the date on which the investee becomes a joint venture. On acquisition of the investment in a joint venture, any excess of the cost of the investment over the Corporation's share of the net fair value of the identifiable assets and liabilities of the investee is recognized as goodwill, which is included within the carrying amount of the investment. Any excess of the Corporation's share of the net fair value of the identifiable assets and liabilities over the cost of the investment, after reassessment, is recognized immediately in earnings or loss.

The requirements of IAS 39 are applied to determine whether it is necessary to recognize any impairment loss with respect to the Corporation's investment in a joint venture. When necessary, the entire carrying amount of the investment (including goodwill) is tested for impairment in accordance with IAS 36 Impairment of Assets as a single asset by comparing its recoverable amount (higher of value in use and fair value less costs to sell) with its carrying amount. Any impairment loss recognized forms part of the carrying amount of the investment. Any reversal of the impairment loss is recognized in accordance with IAS 36 to the extent that the recoverable amount of the investment subsequently increases.

The Corporation discontinues the use of the equity method from the date when the investment ceases to be a joint venture. When the Corporation retains an interest in the former joint venture and the retained interest is a financial asset, the Corporation measures the retained interest at fair value at that date and the fair value is regarded as its fair value on initial recognition in accordance with IFRS 9. The difference between the carrying amount of the joint venture at the date the equity method was discontinued, and the fair value of any retained interest and any proceeds from disposing of a part interest in the joint venture is included in the determination of the gain or loss on disposal of the joint venture. In addition, the Corporation accounts for all amounts previously recognized in other comprehensive income in relation to that joint venture on the same basis as would be required if that joint venture had directly disposed of the related assets or liabilities. Therefore, if a gain or loss previously recognized in other comprehensive income by that joint venture would be reclassified to profit or loss on the disposal of the related assets or liabilities, the Corporation reclassifies the gain or loss from equity to profit or loss (as a reclassification adjustment) when the equity method is discontinued.

Investments in joint operations

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

When the Corporation undertakes its activities under joint operations, the Corporation as a joint operator recognizes in relation to its interest in a joint operation:

- its assets, including its share of any assets held jointly;
- its liabilities, including its share of any liabilities incurred jointly;
- its revenue form the sale of its share of the output arising from the joint operation;
- its share of the revenue from the sale of the output by the joint operation; and
- its expenses, including its share of any expenses incurred jointly.

The Corporation accounts for the assets, liabilities, revenues and expenses relating to its interest in a joint operation in accordance with IFRSs applicable to the particular assets, liabilities, revenues and expenses.

When the Corporation transacts with a joint operation in which a group entity is a joint operator (such as a sale or contribution of assets), the Corporation is considered conducting the transaction with other parties to the joint operation and profits and losses resulting from the transactions are recognized in the Corporation's consolidated financial statements only to the extent of the other parties' interests in the joint operation.

When the Corporation transacts with a joint operation in which a group entity is a joint operator (such as a purchase of assets), the Corporation does not recognize its share of the gains and losses until it resells those assets to a third party.

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The cost of the acquisition is measured at the aggregate of the fair values, at the acquisition date, of assets given, liabilities incurred or assumed, and equity instruments issued by the Corporation in exchange for control of the acquiree. Acquisition-related costs are recognized in the consolidated statement of earnings as incurred. Where appropriate, the cost of acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition when they qualify as measurement period adjustments. All other subsequent changes in the fair value of contingent consideration classified as an asset or liability are accounted for in accordance with the relevant IFRS and reflected through net earnings. Changes in the fair value of contingent consideration classified as equity are not recognized.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, bank balances and short-term investments with original maturities of three months or less, net of bank overdrafts whenever they are an integral part of the Corporation's cash management process.

Restricted cash and short-term investments

The Corporation holds restricted cash and short-term investments as required under some of its project financings.

The restricted cash accounts and short-term investments are currently invested in cash or in short-term investments having maturities of three months or less.

The availability of funds in the restricted cash and short-term investments accounts are restricted by credit agreements.

Reserve accounts

The Corporation holds three types of reserve accounts designed to help ensure its financial stability. The first is the hydrology/wind reserve established at the start of commercial operations of a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind conditions or other unpredictable events. The second is the major maintenance reserve established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. A third reserve is the dismantlement reserve aiming to have sufficient funding available for decommissioning the wind farm at the end of the project. The availability of the funds in the reserve accounts may be restricted by credit agreements.

The reserve accounts are currently invested in cash or in short-term investments having maturities of a year or less as well as in Government-backed securities.

The availability of funds in the reserve accounts may be restricted by credit agreements.

Property, plant and equipment

Property, plant and equipment are comprised mainly of hydroelectric facilities, wind farm facilities and a solar facility that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses if any.

Property, plant and equipment are depreciated using the straight-line method over the lesser of (i) the estimated useful lives of the assets or (ii) the period for which the Corporation owns the rights to the assets. Improvements that increase or extend the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. Property, plant and equipment are not depreciated until they are ready for their intended use.

The estimated useful lives, residual values and depreciation methods are reviewed at the end of each reporting period, with the effect of any changes in estimate accounted for on a prospective basis.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on the disposal or retirement of an item of property, plant and equipment is determined as the difference between the sale proceeds and the carrying amount of the asset and is recognized in earnings.

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale. The total costs of those assets, including the addition of borrowing costs, shall not exceed the recoverable amount of the assets.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization.

All other borrowing costs are recognized in earnings in the period in which they are incurred.

As of October 1, 2017, the Corporation changed the useful life for the depreciation period for some components of the property, plant and equipment assets mainly related to certain Quebec wind farms facilities. The estimated useful life of the speed increasers and the blades, which were formerly equal to 15 and 20 years respectively, were increased to 20 and 25 years, which reflects the state of the assets and the predictive maintenance conducted. This change in estimates was recorded prospectively. The estimated annual impact of this change in accounting estimates is a decrease of $2,932 in annual depreciation expense for the next 12 months. The impact of this change for the period ended December 31, 2017, is a $733 decrease in depreciation expense.

The useful life used to calculate depreciation is as follows:

Type of property, plant and equipment	Ending years of depreciation period	Useful life for the depreciation period
Hydroelectric facilities	2019 to 2092	8 to 75 years
Wind farm facilities	2021 to 2042	14 to 25 years
Solar facility	2032 to 2037	20 to 25 years
Other equipments	2018 to 2024	3 to 10 years

Leases

Leases where the lessor retains substantially all the risks and rewards of ownership are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to income on a straight line basis over the term of the leases.

Intangible assets

Intangible assets consist of various permits, licenses and agreements. Intangibles assets are amortized using the straight-line method over a period ending on the maturity date of the permits, licenses or agreements of each facility. The estimated useful life reflects the respective Power Purchase Agreements' ("PPA") renewable rights periods, since it is the Corporation's intention to exercise its option to renew its PPAs where allowable. They are recorded at cost less accumulated amortization and accumulated impairment losses. Amortization starts when the related facility becomes ready for its intended use.

Intangible assets related to facilities under construction are not amortized until the related facilities are ready for their intended use. Intangible assets were also including the cost of extended warranties for wind farm equipments; these costs were amortized over the warranty period ending in 2016.

The estimated useful life and amortization method are reviewed at the end of each reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

The useful life used to calculate amortization is as follows:

Intangible assets related to:	Ending years of amortization period	Useful life for the amortization period
Hydroelectric facilities	2018 to 2081	4 to 75 years
Wind farm facilities	2024 to 2032	8 to 20 years
Solar facility	2032	20 years

(in thousands of Canadian dollars, except as noted and amounts per share)

Project development costs

Project development costs represent costs incurred for the acquisition of prospective projects and for the development of hydroelectric, wind farm and solar sites. They are recorded at cost less impairment losses. Development phase starts when a public announcement is made by a utility that a prospective project has been selected to be awarded a power purchase agreement. These costs are transferred to property, plant and equipment or intangible assets when construction starts. Current costs for prospective projects are expensed as incurred and costs of a project under development are written off in the year if the project is abandoned. Borrowing costs directly attributable to the acquisition or development are capitalized as project development costs.

Impairment of property, plant and equipment , intangible assets and project development costs other than goodwill

At the end of each reporting period, the Corporation reviews the carrying amounts of its property, plant and equipment, intangible assets and project development costs to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Corporation estimates the recoverable amount of the cash-generating unit to which the asset belongs. Where a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Intangible assets not yet available for use are tested for impairment at least annually, and whenever there is an indication that the asset may be impaired.

Recoverable amount is the greater of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using an after-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognized immediately in earnings.

Where an impairment loss subsequently reverses, the carrying amount of the asset (or a cash-generating unit) is increased to the revised estimate of its recoverable amount, so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset (or cash-generating unit) in prior years. A reversal of an impairment loss is recognized immediately in earnings.

Goodwill

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the amount of the identifiable assets acquired and the liabilities assumed at the date of acquisition. If, after reassessment, the net amount of the identifiable assets acquired and liabilities assumed exceeds the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held interest in the acquiree (if any), the excess is recognized immediately in earnings as a bargain purchase gain.

For purposes of impairment testing, goodwill is allocated to each of the Corporation's cash-generating unit (or groups of cash-generating units) that is expected to benefit from the synergies of the combination.

A cash-generating unit to which goodwill has been allocated is tested for impairment annually, or more frequently when there is indication that the unit may be impaired. If the recoverable amount of the cash-generating unit is less than its carrying amount, the impairment loss is allocated first to reduce the goodwill of the unit. Any impairment loss for goodwill is recognized in earnings. An impairment loss recognized for goodwill is not reversed in subsequent periods.

Other long-term assets

Other long-term assets include security deposits under various agreements and long-term receivables.

Accrual for acquisition of long-term assets

The accrual for acquisition of long-term assets is defined as long-term debt commitments that have been secured and that will be drawn upon to finance the Corporation's projects currently under development or construction.

Provisions and asset retirement obligations

A provision is a liability of uncertain timing or amount. Provisions are recognized into other liabilities when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity's actions whereby, through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, at each period end, of the expenditures required to settle the present obligation considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk adjusted interest rate.

Asset retirement obligations are recorded into other liabilities when those obligations are incurred and are measured as the present value , if a reasonable estimate of the expected costs to settle the liability can be determined, discounted at a current pre-tax rate specific to the liability. In subsequent years, the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings while changes resulting from the revisions to either the timing, the amount of the original estimate of the undiscounted cash flows or a change of the discount rate are accounted for as part of the carrying amount of the related long-lived asset.The carrying amount of the asset retirement obligations is reviewed quarterly to reflect current estimates and changes in the discount rate.

Financial instruments

The Corporation initially recognizes financial assets on the trade date at which the Corporation becomes a party to the contractual provisions of the instrument.

Financial assets are initially measured at fair value. If the financial asset is not subsequently accounted for at fair value through profit or loss, then the initial measurement includes transaction costs that are directly attributable to the asset’s acquisition or origination. On initial recognition, the Corporation classifies its financial assets as subsequently measured at either amortized cost or fair value, depending on its business model for managing the financial assets and the contractual cash flow characteristics of the financial assets.

(i) Financial assets measured at amortized cost
A financial asset is subsequently measured at amortized cost, using the effective interest method and net of any impairment loss, if:
- The asset is held within a business model whose objective is to hold assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise, on specified dates, to cash flows that are solely payments of principal and/or interest.

The Corporation currently classifies its Cash and cash equivalents, restricted cash and short-term investments, accounts receivable, and reserve accounts as assets measured at amortized cost.

(ii) Financial assets measured at fair value
These assets are measured at fair value and changes therein, including any interest or dividend income, are recognized in net earnings unless hedge accounting is used in which case the changes are recognized in comprehensive income.

The Corporation currently classifies its derivative financial instruments as financial assets measured at fair value.

The Corporation derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred.

Financial liabilities are classified into the following categories.

(i) Financial liabilities measured at amortized cost
Non-derivative financial liabilities are initially recognized at fair value less any directly attributable transaction costs. Subsequent to initial recognition, these liabilities are measured at amortized cost using the effective interest method.

The Corporation currently classifies its dividends payable to shareholders, accounts payables and other payables as liabilities as measured at amortized cost.

(ii) Financial liabilities measured at fair value
Financial liabilities at fair value are initially recognized at fair value and are re-measured at each reporting date with any changes therein recognized in net earnings unless hedge accounting is used in which case the changes are recognized in comprehensive income.

The Corporation currently classifies its derivative financial instruments as a financial liability measured at fair value.

The Corporation derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Financial assets and liabilities are offset and the net amount presented in the consolidated statement of financial position when, and only when, the Corporation has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Financial instruments are classified in fair value hierarchy levels as follows:

Level 1 valuation based on quoted prices (unadjusted) in active markets to which the entity has access at the evaluation date for identical assets or liabilities;
Level 2 valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);
Level 3 valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value. The Corporation recognizes transfers between levels of the fair value hierarchy at the end of the reporting period during which the change has occurred.

Impairment of financial assets

The Corporation assesses at the end of each reporting period whether there is objective evidence that a financial asset or group of financial assets is impaired. Evidence of impairment may include indications that the debtors or a group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganization, and where observable data indicates that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults. Impairment losses are recorded in other net expenses (revenues) if applicable.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized (such as an improvement in the debtor's credit rating), the reversal of the previously recognized impairment loss is recognized in the consolidated statement of earnings.

Hedging relationships

The Corporation enters into derivative financial instruments to hedge its market risk exposures. On initial designation of new hedges the Corporation formally documents the relationship between the hedging instruments and hedged items, including the risk management objectives and strategy in undertaking the hedge transaction, together with the methods that will be used to assess the effectiveness of the hedging relationship. The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

For a cash flow hedge of a forecasted transaction, the transaction should be highly probable to occur and should present an exposure to variations in cash flows that could ultimately affect reported net earnings.

Derivatives are recognized initially at fair value, and attributable transaction costs are recognized in net earnings as incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein are accounted for as described below.

Cash flow hedges

When a derivative is designated as the hedging instrument in a hedge of the variability in cash flows attributable to a particular risk associated with a recognized asset or liability or a highly probable forecasted transaction that could affect net earnings, the effective portion of changes in the fair value of the derivative is recognized in other comprehensive income and presented in accumulated other comprehensive income as part of equity. The amount recognized in other comprehensive income is removed and included in net earnings under the same line item in the consolidated statement of earnings as the hedged item, in the same period that the hedged cash flows affect net earnings. Any ineffective portion of changes in the fair value of the derivative is recognized immediately in net earnings. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated or exercised, then hedge accounting is discontinued prospectively. The cumulative gain or loss previously recognized in other comprehensive income remains in accumulated other comprehensive income until the forecasted transaction affects net earnings. If the forecasted transaction is no longer expected to occur, then the balance in accumulated other comprehensive income is recognized immediately in net earnings.

Net investment in foreign operation hedges

The Corporation applies hedge accounting to foreign currency differences arising between the functional currency of the foreign operation and Corporation's functional currency (Canadian dollars).

Foreign currency differences arising on the translation of a financial liability designated as a hedge of a net investment in a foreign operation are recognized in other comprehensive income to the extent that the hedge is effective, and are presented within equity in the accumulated other comprehensive income. Any ineffective portion of changes in the hedging instruments is recognized directly in net earnings. When the hedged part of a net investment is disposed of, the relevant amount in the accumulated other comprehensive income is transferred to the statement of earnings as part of the profit or loss on disposal.

Embedded derivatives

Derivatives embedded in non-derivative host contracts are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the contracts are not measured at fair value through profit or loss.

Non-controlling interests

Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Corporation's equity therein. The interest of non-controlling shareholders may be initially measured either at fair value or at the non-controlling interest's proportionate share in the recognized amounts of the acquiree's identifiable net assets. The choice of measurement basis is made on an acquisition by acquisition basis. Subsequent to acquisition, non-controlling interests consist of the amount attributed to such interests at initial recognition and the non-controlling interest's share of changes in equity since the date of the acquisition.

Revenue recognition

Revenues are recognized, on an accrual basis, upon delivery of electricity at rates provided for under the PPAs entered into with the purchasing utilities or upon compensations from insurance or suppliers for loss of revenues when it is virtually certain that the claim will be received.

Government assistance

Government assistance in the form of subsidies or refundable investment tax credits are recorded in the consolidated financial statements when there is reasonable assurance that the Corporation complied with all conditions necessary to obtain the assistance.

The Corporation is entitled to subsidies under the EcoEnergy program. The subsidies are equal to 1¢ per KWh produced for the first 10 years following commisionning of each facility. The Ashlu Creek, Fitzsimmons Creek, Douglas Creek, Fire Creek, Stokke Creek, Tipella Creek, Lamont Creek, Upper Stave River, Magpie River (ended in June 2017) and Umbata Falls hydro facilities and the Carleton, Baie-des-Sables (ended in March 2017) and L'Anse-à-Valleau wind farms are entitled to the subsidies. As per the electricity purchase agreements, the Corporation must transfer 75% of the Carleton, Baie-des-

Sables and L'Anse-à-Valleau wind farms subsidies to Hydro-Québec. Gross EcoEnergy subsidies of $11,177 ($15,227 in 2016) are included in the revenues and the 75% payable to Hydro-Québec for the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms are included in the operating expenses.

The Corporation incurs renewable energy development expenditures, which are eligible for refundable investment tax credits. The recorded investment tax credits are based on management's estimates of amounts expected to be recovered and are subject to an audit by the taxation authorities. Investment tax credits for renewable energy development expenditures are reflected as a reduction in the cost of the assets or expenses to which they relate.

Share-based payment

The Corporation measures equity-settled stock option awards using the fair value method. Expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of options that will eventually vest. Each equity-settled stock option award that vests in installments is accounted for as a separate award with its own distinct fair value measurement. The fair value of options is amortized to earnings over the vesting period with an offset to share-based payment in equity. For options that are forfeited before vesting, the compensation expense that had previously been recognized and the offset to share-based payment in equity are reversed. When options are exercised, the corresponding share-based payment in equity and the proceeds received by the Corporation are credited to share capital.

Performance share plan (“PSP plan”)

The Corporation measures equity-settled action awards using the fair value method. Expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of shares that will eventually vest and a corresponding liability is recorded. For shares that are forfeited before vesting, the expense that had previously been recognized is reversed. When shares are purchased by the Fiduciary on the secondary market, the corresponding fair value is debited to common shares capital. On the vesting date, each performance share right entitles its holder to one common share of the Corporation with all the reinvested dividends accrued thereon from the grant date. When paid, the corresponding fair value is credited from the common share capital against the corresponding liability.

Cash settled share-based payment

Under the Corporation’s Deferred Share Unit Plan (the “DSU Plan”), Directors and officers may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation. The Corporation cash-settled share-based payments are measured at fair value at the grand date with a corresponding liability. Until the liability is settled, the fair value of the liability is remeasured at the end of each reporting period and at the date of settlement, with any changes in fair value recognized in income. DSUs cannot be redeemed for cash until the Director leaves the Board or the officer leaves.

Foreign currency translation

The Corporation and its subsidiaries each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rate in effect on the transaction date. The resulting translation gains and losses are included in other comprehensive income (loss) with the cumulative gain or loss reported in accumulated other comprehensive income. Amounts previously recognized in accumulated other comprehensive income are recognized in earnings when there is a reduction in the net investment.

The Corporation designates a portion of its U.S. dollar-denominated debt to hedge its investment in its U.S. functional currency foreign operations. The Corporation also designates a portion of its foreign exchange forwards to hedge its investment in its Euro functional currency foreign operations.Translation gains or losses on the portion of the debt and foreign exchange forwards designated as hedges are included in other comprehensive income with the cumulative gain or loss reported in accumulated other comprehensive income. The gain or loss relating to the portion of the debt and foreign exchange forwards in excess of the investment in the foreign subsidiaries is recognized immediately in earnings. Gains and losses on the hedging instrument relating to the effective portion of the hedge accumulated in the foreign currency translation reserve are reclassified to earnings in the same way as exchange differences relating to the foreign operations.

The Corporation formally documents these hedges. On a quarterly basis, the Corporation reviews the hedges to ensure that they effectively offset the translation gains or losses arising from its investment in its U.S. and its Euro functional currencies foreign operations.

The exchange rates for the currencies used in the preparation of the consolidated financial statements were as follow:

	Exchange rates as at		Average exchange rates for fiscal years	
	December 31, 2017	December 31, 2016	2017	2016
Euro	1.5052	1.4169	1.4652	1.4380
US dollar	1.2545	1.3427	1.2980	1.3256

Income taxes

Current tax and deferred tax are recognized in earnings except to the extent that it relates to a business combination, or to items recognized directly in equity or in other comprehensive income (loss).

Current tax is the expected tax on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date.

Deferred tax is not recognized in respect of subsidiaries for the temporary differences between the carrying amounts of the investments and the tax basis, unless such differences are expected to reverse in the foreseeable future.

Deferred tax assets are recognized to the extent that it is probable that taxable profits will be available against which the deductible temporary differences can be utilized.

Earnings (loss) per share

Basic earnings (loss) per share are computed by dividing net earnings available to common shareholders by the weighted average number of shares outstanding during the year.

The Corporation uses the treasury stock method for calculating diluted earnings (loss) per share. Diluted earnings (loss) per share are computed similarly to basic earnings (loss) per share except that the weighted average shares outstanding are increased to include additional shares from the assumed conversion of convertible debentures and the exercise of stock options, if dilutive. The number of additional shares is calculated by assuming that convertible debentures were converted and that outstanding stock options were exercised and that the proceeds from such exercises were used to acquire shares at the average market price during the year.

4. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

Significant estimates and assumptions

(in thousands of Canadian dollars, except as noted and amounts per share)

The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. During the reporting periods, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment, intangible assets, project development costs and goodwill, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives, effectiveness of hedging relationships and classification of structured entities. These estimates and assumptions are based on current market conditions, management's planned course of action and assumptions about future business and economic conditions. Changes in the underlying assumptions and estimates could have a material impact on the reported amounts. These estimates are reviewed periodically. If adjustments prove necessary, they are recognized in earnings in the period in which they are made.

Critical judgments and estimates

Fair Value of Financial Instruments

Certain financial instruments, such as derivative financial instruments, are carried in the consolidated statements of financial position at fair value, with changes in fair value reflected in earnings unless hedge accounting is used in which case the changes are recognized in comprehensive income. Fair values of some financial instruments are estimated by using valuation techniques using several assumptions such as interest rate, credit spread and risk.

Useful Lives of Property, plant and equipment and Intangible assets

Property, plant and equipment and intangible assets represent a significant proportion of the Corporation's total assets. The Corporation reviews estimates of the useful lives of property, plant and equipment and Intangible assets on an annual basis and adjust depreciation on a prospective basis, if necessary.

Goodwill Impairment

The Corporation makes a number of estimates when calculating the recoverable amount of goodwill using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the numbers of years used in the cash flow model, and the discount rate.

Impairment of Property, plant and equipment, Intangible assets and Project development costs

The Corporation makes a number of estimates when calculating recoverable amount value using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the number of years used in the cash flow model, and the discount rate. The likelihood of being able to develop future projects is also assessed in regards of the competitive business environment and the willingness expressed by the governmental authorities of procuring additional sources of energy.

Business acquisition fair value

The Corporation makes a number of estimates when determining the acquisition date fair values of assets and liabilities acquired in a business acquisition. Fair values are estimated by using valuation techniques using several assumptions such as future production, earnings and expenses, interest and discount rates.

Structured entity

Based on the contractual arrangements between the Corporation and the other respective partner, the Corporation concluded that it has control over Kwoiek Creek Resources L.P and Mesgi'g Ugju's'n (MU) Wind Farm L.P.

Asset retirement obligations

The Corporation makes a number of estimates when calculating fair value of the amount of obligation using discounted rate. The obligation is measured at its present value using a current market-based, risk adjusted interest rate.

Hedging

The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

Income Taxes

The calculation of income taxes requires judgment in interpreting tax rules and regulations. The Corporation's tax filings are also subject to audits, the outcome of which could change the amount of current and deferred tax assets and liabilities. The Corporation believes that it has sufficient amounts accrued for outstanding tax matters based on the information that currently is available. Deferred tax assets and liabilities require management's judgment in determining the amounts to be recognized. In particular, judgment is required when assessing the timing of reversal of temporary differences to which future income tax rates are applied. Further, the amount of deferred tax assets, which is limited to the amount that is probable to be realized, is estimated with consideration given to the timing, sources and amounts of future taxable profit.

5. BUSINESS ACQUISITIONS

a. Acquisition of Yonne wind facility

On February 21, 2017, the Corporation finalized the acquisition of an operating wind facility located in France ("Yonne"). The purchase price for the wind power project was a net cash consideration of €35,184 (all amounts in € are in thousands of €) ($48,983). A €10,000 ($13,922) deposit had already been provided by the Corporation in the year 2016.

All power generated from the operating facility is sold to Electricité de France.

Additional cash flows generated from the asset acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. Yonne added an additional gross installed capacity of 44 MW to the Corporation's portfolio of operational wind farms.

The Corporation owns a 69.55% interest in the project and the Régime de rentes du Mouvement Desjardins ("RRMD") owns the remaining 30.45%.

The following table reflects the final allocation of the purchase price to the fair value of the net assets acquired:

	Preliminary purchase price allocation previously disclosed	Subsequent adjustments	Final purchase price allocation	
	€	€	€	$
Cash and cash equivalents	3,583	—	3,583	4,989
Accounts receivable	12,936	—	12,936	18,009
Prepaid and others	351	—	351	488
Property, plant and equipment	76,629	1,542	78,171	108,830
Intangible assets	24,138	(6,446)	17,692	24,631
Goodwill	—	4,539	4,539	6,319
Accounts payable and other payables	(712)	—	(712)	(991)
Long-term debt	(72,753)	—	(72,753)	(101,287)
Derivative financial instruments	(683)	—	(683)	(951)
Asset retirement obligations	(1,855)	(1,546)	(3,401)	(4,735)
Deferred tax liabilities	(6,450)	1,911	(4,539)	(6,319)
Net assets acquired	35,184	—	35,184	48,983

Adjustments have been made to reflect the final valuation of some elements of the purchase price allocation.

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3 (see note 8).

If the acquisition had taken place on January 1, 2017, the consolidated revenues and net earnings for the year ended December 31, 2017 would have been $401,724 and $20,284 respectively.

The amounts of revenues and net loss of the facilities since February 21, 2017 included in the consolidated statement of earnings are $8,470 and $13 respectively for the 314 days ended December 31, 2017.

b. Acquisition of Rougemont 1-2 and Vaite wind facilities

On May 24, 2017, the Corporation finalized the acquisition of Rougemont 1-2 and Vaite projects located in France ("Rougemont 1-2 and Vaite"). The purchase price for Rougemont 1-2 and Vaite is a cash consideration of €51,380 (all amounts in € are in thousands of €) ($77,773), subject to certain adjustments.

All power generated from the operating facilities is sold to Electricité de France.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. Rougemont 1-2 and Vaite added an additional gross installed capacity of 119,5 MW to the Corporation's portfolio of wind farms.

The Corporation owns a 69.55% interest in the project and the RRMD owns the remaining 30.45%.

The following table reflects the adjusted preliminary allocation of the purchase price to the fair value of the net assets acquired:

	Preliminary purchase price allocation previously disclosed	Subsequent adjustments	Adjusted preliminary purchase price allocation	
	€	€	€	$
Cash and cash equivalents	45	—	45	68
Restricted cash and short term investments	6,443	—	6,443	9,752
Accounts receivable	4,699	—	4,699	7,113
Prepaid and others	52	—	52	79
Property, plant and equipment	165,183	779	165,962	251,217
Intangible assets	39,833	(5,047)	34,786	52,656
Goodwill	—	7,827	7,827	11,848
Accounts payable and other payables	(5,612)		(5,612)	(8,495)
Income tax payable	(252)		(252)	(382)
Long-term debt	(138,551)	(6,076)	(144,627)	(218,922)
Derivative financial instruments	(6,645)		(6,645)	(10,059)
Asset retirement obligations	(2,944)	(779)	(3,723)	(5,636)
Deferred tax liabilities	(10,871)	3,296	(7,575)	(11,466)
Net assets acquired	51,380	—	51,380	77,773

Adjustments have been made to reflect the updated valuation of some elements of the purchase price allocation. The purchase price allocation remains subject to the completion of the valuation of working capital adjustments, intangible assets, goodwill, long-term debt and consequential adjustments.

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3 (see note 8).

If the acquisition had taken place on January 1, 2017, the consolidated revenues and net earnings for the year ended December 31, 2017 would have been $404,341 and $21,611 respectively.

The amounts of revenues and net earnings of the facilities since May 24, 2017 included in the consolidated statement of earnings are $14,113 and $1,572 respectively for the 221 days ended December 31, 2017.

c. Acquisition of Plan Fleury and Les Renardières wind facilities

On August 25, 2017, the Corporation finalized the acquisition of Plan Fleury and Les Renardières projects located in France ("Plan Fleury and Les Renardières"). The purchase price for Plan Fleury and Les Renardières is a cash consideration of €27,352 (all amounts in € are in thousands of €) ($40,839), subject to certain adjustments.

All power generated from the operating facilities is sold to Electricité de France.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. Plan Fleury and Les Renardières added an additional gross installed capacity of 43 MW to the Corporation's portfolio of wind farms.

The Corporation owns a 69.55% interest in the project and the RRMD owns the remaining 30.45%.

The following table reflects the preliminary allocation of the purchase price to the fair value of the net assets acquired:

	Preliminary purchase price allocation previously disclosed	Subsequent adjustments	Adjusted preliminary purchase price allocation	
	€	€	€	$
Cash and cash equivalents	186		186	277
Restricted cash and short term investments	19,639		19,639	29,322
Accounts receivable	13,123		13,123	19,595
Prepaid and others	168		168	250
Property, plant and equipment	67,579		67,579	100,903
Intangible assets	37,498	(11,044)	26,454	39,499
Goodwill	—	7,772	7,772	11,604
Accounts payable and other payables	(24,690)		(24,690)	(36,865)
Long-term debt	(75,107)		(75,107)	(112,142)
Deferred tax liabilities	(11,044)	3,272	(7,772)	(11,604)
Net assets acquired	27,352	—	27,352	40,839

Adjustments have been made to reflect the updated valuation of some elements of the purchase price allocation. The purchase price allocation remains subject to the completion of the valuation of working capital adjustments, intangible assets, goodwill, long-term debt and consequential adjustments.

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3 (see note 8).

If the acquisition had taken place on January 1, 2017, the consolidated revenues and net earnings for the year ended December 31, 2017 would have been $400,263 and $19,628 respectively.

The amounts of revenues and net earnings of the facilities since August 25, 2017 included in the consolidated statement of earnings are $3,280 and $1,309 respectively for the 129 days ended December 31, 2017.

d. Acquisition of 2 additional French wind farms in Nouvelle-Aquitaine (France)

On December 22, 2016, the Corporation finalized the acquisition of 2 operating wind facilities located in France ("the Two French Entities Acquired in Nouvelle-Aquitaine"). The purchase price for the wind power projects was a net cash consideration of €16,123 ($22,698), subject to certain adjustments. In December 2017, an adjustment of €582 ($876) has been made to the purchase price and the calculation of asset retirement obligations was finalized.

All power generated from the operating facilities is sold to Électricité de France.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. The Two French Entities Acquired in Nouvelle-Aquitaine added an additional gross installed capacity of 24 MW to the Corporation's portfolio of operational wind farms.

The Corporation owns a 69.55% interest in the project and the Régime de rentes du Mouvement Desjardins (RRMD) owns the remaining 30.45%.

(in thousands of Canadian dollars, except as noted and amounts per share)

The following table reflects the final purchase price allocation of the purchase price to the fair value of the net assets acquired:

	Preliminary purchase price allocation previously disclosed	Subsequent adjustments	Final purchase price allocation	
	€	€	€	$
Cash and cash equivalents	79	—	79	111
Accounts receivable	9,022	—	9,022	12,700
Prepaid and others	6	—	6	8
Reserve accounts	1,400	—	1,400	1,971
Property, plant and equipment	43,858	1,200	45,058	63,429
Intangible assets	14,410	(740)	13,670	19,171
Accounts payable and other payables	(12,271)		(12,271)	(17,274)
Long-term debt	(34,235)		(34,235)	(48,193)
Asset retirement obligations	(1,312)	(1,200)	(2,512)	(3,535)
Deferred tax liabilities	(4,834)	158	(4,676)	(6,566)
Net assets acquired	16,123	(582)	15,541	21,822

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3 (see note 8).

e. Acquisition of 7 operating wind facilities in France

The final valuation of the April 2016 acquisition of 7 operating wind facilities has been made and no adjustment was required to the purchase price allocation since the latest annual report.

	Final purchase price allocation	
	€	$
Cash and cash equivalents	8,050	11,887
Accounts receivable	2,315	3,419
Prepaid and others	1,018	1,503
Reserve accounts	4,449	6,570
Property, plant and equipment	106,543	157,330
Intangible assets	51,258	75,692
Accounts payable and other payables	(1,952)	(2,882)
Current portion of derivative financial instruments	(42)	(62)
Long-term debt	(88,150)	(130,170)
Derivative financial instruments	(213)	(315)
Asset retirement obligations	(3,129)	(4,620)
Deferred tax liabilities	(16,176)	(23,887)
Net assets acquired	63,971	94,465

(in thousands of Canadian dollars, except as noted and amounts per share)

6. OPERATING EXPENSES

	Year ended December 31	
	2017	2016
Salaries	5,287	4,421
Insurance	4,308	2,894
Operation and maintenance	32,190	22,398
Property taxes and royalties	29,887	21,756
	71,672	51,469

Depreciation and amortization recorded in the consolidated statements of earnings are mainly related to operating expenses incurred to generate revenues.

7. FINANCE COSTS

	Year ended December 31	
	2017	2016
Interest on long-term debt and on convertible debentures	134,420	86,687
Inflation compensation interest	3,910	4,207
Amortization of financing fees	2,980	1,194
Accretion of long-term debt and convertible debentures	1,404	1,442
Accretion expenses on other liabilities	1,664	551
Others	2,388	1,173
	146,766	95,254

8. OTHER NET EXPENSES

	Year ended December 31	
	2017	2016
Transaction costs	6,450	2,547
Realized gain on foreign exchange	(910)	(1,008)
(Gain) loss on contingent considerations 23 a)	(881)	800
Other net revenues	(2,644)	(1,599)
Loss on disposal of property, plant and equipment	888	—
Recovery of loan impairment	(450)	(475)
	2,453	265

9. INVESTMENTS IN JOINT VENTURES

9.1 Details of material joint ventures

Details of the Corporation's material joint ventures at the end of the reporting periods are as follows:

(in thousands of Canadian dollars, except as noted and amounts per share)

Name of joint venture	Principal activity	Place of creation and principal place of operation	Proportion of ownership interest and voting rights held by the Corporation	
			December 31, 2017	December 31, 2016
Umbata Falls, L.P.	Own and operate an hydroelectric facility	Ontario	49%	49%
Viger-Denonville, L.P.	Own and operate a wind farm	Québec	50%	50%

The joint ventures are accounted for using the equity method in these consolidated financial statements.

The summarized financial information below represents amounts shown in the joint venture's financial statements prepared in accordance with IFRSs.

Umbata Falls, L.P.

Summary Statements of Earnings and Comprehensive Income

	Year ended December 31	
	2017	2016
Revenues	11,645	9,429
Operating, general and administrative expenses	1,307	938
	10,338	8,491
Finance costs	2,392	2,507
Other net expenses (revenues)	23	(31)
Depreciation and amortization	4,016	4,017
Unrealized net gain on derivative financial instruments	(2,056)	(526)
Net earnings and comprehensive income	5,963	2,524

Summary Statements of Financial Position

As at	December 31, 2017	December 31, 2016
Cash and cash equivalents	1,620	1,010
Other current assets	1,930	1,080
Current assets	3,550	2,090
Non-current assets	60,658	64,647
	64,208	66,737
Accounts payable and other payables	198	138
Other current liabilities	3,314	2,895
Current liabilities	3,512	3,033
Non-current liabilities	40,924	46,173
Partner's equity	19,772	17,531
	64,208	66,737

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	December 31, 2017	December 31, 2016
Net assets of the joint venture	19,772	17,531
Proportion of the Corporation's ownership interest in the joint venture	49%	49%
Carrying amount of the Corporation's interest in the joint venture	9,688	8,590

(in thousands of Canadian dollars, except as noted and amounts per share)

Umbata Falls, L.P. 's Debt

The loan consist of a five-year term loan, amortized over a 18.5-year period starting in April 2015. The loan bears interest at the bankers' acceptance rate plus an applicable credit margin for an all-in rate of 5.48%. The quarterly repayments are increased by a cash flow sweep calculated as follow: the percentage of excess of actual production over the forecasted production multiply by the quarterly excess cash flow.

The lender also agreed to make available a letter of credit facility in a principal amount not exceeding $500. As at December 31, 2017, an amount of $470 has been used to secure two letters of credit. This debt is secured by all of Umbata Falls LP's assets with a carrying value of $64,208.

Umbata Falls, L.P. holds an amortizing interest rate swap contract of $41,621 as at December 31, 2017 ($43,005 in 2016), maturing in 2034 and bearing an interest rate of 3.98%.

Viger-Denonville, L.P.

Summary Statements of Earnings and Comprehensive Income

	Year ended December 31	
	2017	2016
Revenues	10,998	10,293
Operating, general and administrative expenses	1,899	1,844
	9,099	8,449
Finance costs	3,466	3,635
Other net revenues	(40)	(30)
Depreciation and amortization	2,815	2,923
Unrealized net gain on derivative financial instruments	(704)	(658)
Net earnings	3,562	2,579
Other comprehensive income	1,501	2
Total comprehensive income	5,063	2,581

Summary Statements of Financial Position

As at	December 31, 2017	December 31, 2016
Cash and cash equivalents	1,760	840
Other current assets	1,245	1,409
Current assets	3,005	2,249
Non-current assets	53,812	56,583
	56,817	58,832
Accounts payable and other payables	744	446
Other current liabilities	3,611	3,929
Current liabilities	4,355	4,375
Non-current liabilities	49,920	54,223
Partner's equity	2,542	234
	56,817	58,832

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

(in thousands of Canadian dollars, except as noted and amounts per share)

As at	December 31, 2017	December 31, 2016
Net assets of the joint venture	2,542	234
Proportion of the Corporation's ownership interest in the joint venture	50%	50%
Carrying amount of the Corporation's interest in the joint venture	1,271	117

Viger-Denonville, L.P. 's Debt

The loan consists of a 18-year term loan, amortized over an 18-year period which started in June 2014. The term loan carries a floating interest rate equal to the banker's acceptance rate plus an applicable margin for an all-in rate of 6.00%. The principal repayments are variable and set to $2,864 for 2018. The lenders also agreed to make available a letter of credit facility in an amount not to exceed $984. As at December 31, 2017, an amount of $984 has been used to secure one letter of credit. These loans are secured by Viger-Denonville, L.P's assets with a carrying value of $56,817.

Viger-Denonville, L.P. holds an amortizing interest rate swap contract of $49,262 as at December 31, 2017 ($51,847 in 2016), maturing in 2031 and bearing an interest rate of 3.40%.

9.2 Commitments of joint ventures

As at December 31, 2017, the Corporation's share of the expected schedule of commitment payments for Umbata Falls, L.P. and Viger-Denonville, L.P. is as follows:

Years of	Hydroelectric Generation	Wind Power Generation	Total
2018	2	240	242
2019	2	243	245
2020	2	246	248
2021	2	249	251
2022	2	252	254
Thereafter	37	2,356	2,393
Total	47	3,586	3,633

Umbata Falls, L.P.

The partnership will be dissolved in 2034, which is 25 years after the beginning of operations. Upon the dissolution of the partnership, the property and assets of the partnership shall be transferred to the other partner for no consideration.

Viger-Denonville, L.P.

Parc Eolien Communautaire Viger-Denonville LP entered into royalties and other commitments related to amounts to set aside for the dismantling of wind farm components, commitments to surrounding municipalities and land owners and the operation of the wind farms.

10. DERIVATIVE FINANCIAL INSTRUMENTS

The Corporation holds interest rate swap contracts and bond forwards contracts (“Interest hedging instruments”) that enable it to hedge its exposure to the floating interest rates payable on the portion of its long-term debt. The Corporation also holds foreign exchange forwards contracts (“foreign exchange forward”) that enable it to hedge its exposure to foreign exchange rate on its investments in France. The counterparties to the contracts are major financial institutions; the Corporation does not anticipate any payment defaults on their part. The estimated impact of an increase in swap rates curve of 0.1% would decrease the negative fair value of these financial instruments by $6,086. Conversely, a decrease in swap rates curve of 0.1% would result in an increase of $6,267 of the negative fair value of these financial instruments. The estimated impact of an increase of 1% in the euro exchange rate against the Canadian dollar would increase the negative fair value of these financial instruments by $3,541. Conversely, a decrease in the euro exchange rate against the Canadian dollar of 1.0% would result in a positive fair value of $3,541 of these financial instruments.

(in thousands of Canadian dollars, except as noted and amounts per share)

The Corporation records embedded derivatives separately from the host contracts:

- The inflation embedded derivative relates to provisions establishing minimum inflation rate at 3% of the selling prices provided for under some of the PPAs entered into with Hydro-Québec. The Corporation does not anticipate any payment defaults from the counterparty. The fair value of these financial instruments is evaluated using revenue estimates based on long-term production averages estimated for each facility. It varies based on the difference between the 3% minimum inflation rate and the long-term inflation rate, which is estimated at 2% as at December 31, 2017 over the remaining terms of these agreements, discounted at a rate of 3.11%. The expected impact of a 0.1% increase in the long-term inflation rate would reduce the fair value of these financial instruments by $172 a 0.1% decrease in the long-term inflation rate would increase the fair value of these financial instruments by $172.

The classification of the fair value hierarchy of all the financial assets and liabilities remained the same during 2017.

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2017	(8)	(62,790)	2,707	(60,091)
Derivatives acquired on business acquisitions (Note 5)	—	(11,010)	—	(11,010)
Variation in fair value of derivative financial instruments in statement of earnings [1]	(16,224)	10,798	(972)	(6,398)
Variation in fair value of derivative financial instruments recognized in other comprehensive income	(1,062)	16,307	—	15,245
Net foreign exchange differences	—	(15)	—	(15)
As at December 31, 2017	(17,294)	(46,710)	1,735	(62,269)

1. On the statement of earnings, a gain of $8,643 is also recognized in unrealized net (gain) loss on financial instruments, resulting from an intragroup loan. On consolidation, although the intragroup loan is eliminated from the consolidated statement of financial position, the related exchange loss recognized in the consolidated statement of earnings survives the consolidation process.

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2016	—	(71,685)	3,977	(67,708)
Derivatives acquired on business acquisitions (Note 5)	—	(377)	—	(377)
Variation in fair value of derivative financial instruments recognized in statement of earnings[1]	(39)	8,904	(1,270)	7,595
Variation in fair value of derivative financial instruments recognized in other comprehensive income	31	352	—	383
Net foreign exchange differences	—	16	—	16
As at December 31, 2016	(8)	(62,790)	2,707	(60,091)

1. On the statement of earnings, a loss of $3,303 is also recognized in unrealized net (gain) loss on financial instruments, resulting from an intragroup loan. On consolidation, although the intragroup loan is eliminated from the consolidated statement of financial position, the related exchange loss recognized in the consolidated statement of earnings survives the consolidation process.

Reported in the consolidated statements of financial position:

As at	December 31, 2017	December 31, 2016
Current assets – derivative financial instruments	5,416	1,527
Non-current assets – derivative financial instruments	9,558	8,117
Current liabilities – derivative financial instruments	(22,749)	(14,541)
Non-current liabilities – derivative financial instruments	(54,494)	(55,194)
	(62,269)	(60,091)

(in thousands of Canadian dollars, except as noted and amounts per share)

Interest rate risk

The terms of the contracts reducing the Corporation's risk of interest rate fluctuations are as follows:

Contracts	Maturity	Early termination option	Notional Amounts December 31, 2017	Notional Amounts December 31, 2016
Contracts used to hedge the interest rate risk				
Interest rate swap, 0.96%	2017	None	—	49,250
Interest rate swaps, 4.27% to 4.41%	2018	None	82,600	82,600
Bond forwards, 1.74%	2018	None	50,000	—
Interest rate swaps, 2.33%	2024	2019	20,000	20,000
Interest rate swaps, 2.30%	2024	2019	20,000	20,000
Interest rate swap, 1.91%, amortizing	2026	None	98,056	103,000
Interest rate swaps, 2.94% to 4.83%, amortizing	2026	None	39,151	42,781
Interest rate swaps, from 3.35% to 3.50%, amortizing	2027	None	29,831	32,524
Interest rate swaps, 2.1825%	2027	2022	20,000	—
Interest rate swaps, 2.325%	2028	2022	30,000	—
Interest rate swaps, 2.3275%	2028	2022	52,600	—
Interest rate swap, 3.74%, amortizing	2030	None	79,947	84,532
Interest rate swap, 4.22%, amortizing	2030	2021	23,361	24,534
Interest rate swap, 2.64%, amortizing, translated at CAD 1.5052/Euro	2030	None	15,537	14,736
Interest rate swap, 4.25%, amortizing	2031	2018	37,035	38,771
Interest rate swap, 0.78%, amortizing, translated at CAD 1.5052/Euro	2031	None	67,132	—
Interest rate swap, 1.302%, amortizing, translated at CAD 1.5052/Euro	2032	None	71,620	—
Interest rate swap, 1.303%, amortizing, translated at CAD 1.5052/Euro	2032	None	43,553	—
Interest rate swap, 1.475%, amortizing, translated at CAD 1.5052/Euro	2032	None	13,753	—
Interest rate swap, 1.277%, amortizing, translated at CAD 1.5052/Euro	2032	None	77,024	—
Interest rate swap, 4.61%, amortizing	2035	2025	92,455	95,292
Interest rate swap, 2.85%, amortizing	2041	2021	18,314	18,704
			981,969	626,724

During the year, the Corporation entered into hedge agreements to mitigate the risk of fluctuations in the interest rates on its long-term debt.

The wind farms acquired in 2017 hold interest rate swaps to mitigate the risk of fluctuations in the interest rates on their long-term debts. Hedge accounting is applied on these contract. Rates on contracts represent the interest rate, excluding the applicable margin on the debts.

(in thousands of Canadian dollars, except as noted and amounts per share)

Foreign exchange risk

As part of the Yonne, Rougemont 1-2 and Vaite and Plan Fleury and Les Renardières Acquisitions, the Corporation entered into hedge agreements to reduce the Corporation's foreign exchange risk.

Contracts	Maturity	Early termination option	Notional Amounts December 31, 2017	Notional Amounts December 31, 2016
Contracts used to hedge the foreign exchange risk				
Foreign exchange forwards amortizing until 2041, allowing translation at a fixed rate of CAD 1.7575/ Euro	2018	None	162,881	164,375
Foreign exchange forwards amortizing until 2042, allowing translation at a fixed rate of CAD 1.7588/ Euro	2018	None	50,671	52,156
Foreign exchange forwards amortizing until 2041, allowing translation at a fixed rate of CAD 1.7150/ Euro	2019	None	113,938	—
Foreign exchange forwards amortizing until 2043, allowing translation at a fixed rate of CAD 1.7890/ Euro	2019	None	170,208	—
Foreign exchange forwards amortizing until 2043, allowing translation at a fixed rate of CAD 1.80110/ Euro	2019	None	81,882	—
			579,580	216,531

A portion of the Libor advances of US$13,900 ($17,438) drawn on the revolving credit facilities available until 2022, is used as a hedge on the investment in self-sustaining foreign subsidiaries.

Hedging instruments

As at December 31, 2017, the following items were designated as cash-flow hedging instruments to mitigate the interest rate risk and the foreign exchange risk:

	Notional amount of the hedging instrument	Carrying amount of the hedging instrument Assets	Carrying amount of the hedging instrument Liabilities	Cumulative changes in fair value used for calculating hedge ineffectiveness
Cash-flow hedges:				
Interest rate risk				
Interest rate swaps	932,026	2,400	(49,434)	14,716
Net investment hedges:				
Foreign exchange risk				
Libor advances	11,129	—	11,129	735
Foreign exchange forwards	24,173	318	(1,260)	(1,182)

All the hedging instruments are accounted for in the short-term or long-term portion of derivative financial instruments in the consolidated statements of financial position.

(in thousands of Canadian dollars, except as noted and amounts per share)

The following table summarizes the Corporation's hedged items as at December 31, 2017:

	Cumulative changes in fair value used for calculating hedge ineffectiveness	Cash flow hedge reserve [1]	Foreign currency translation reserve
Cash-flow hedge:			
Interest rate risk			
Interest rate swaps	(13,653)	13,634	—
Hedge of net investment in a foreign operation:			
Foreign exchange risk			
Libor advances	(735)	—	735
Foreign exchange forwards	1,207	127	(1,168)

1. The balance of cash flow hedge reserve for which hedge accounting is no longer applied is nil.

The following table summarizes the impact of hedge ineffectiveness and hedging gains or losses as at December 31, 2017:

	Changes in fair value of the hedging instrument recognized in other comprehensive income	Hedge ineffectiveness recognized in profit or loss	Amount reclassified from the cash flow hedge reserve to profit or loss	Amount reclassified from the foreign currency translation reserve to profit or loss	Line item affected in profit or loss resulting from the reclassification
Cash-flow hedge:					
Interest rate risk					
Interest rate swaps	16,307	729	—	—	—
Hedge of net investment in a foreign operation:					
Foreign exchange risk					
Libor advances	807	—	—	—	—
Foreign exchange forwards	(1,062)	(39)	94	—	—

Ineffectiveness is accounted for in the unrealized net loss (gain) on financial instruments in the consolidated statements of earnings.

Hedging ineffectiveness can result from the credit valuation adjustment applied to the fair value of hedging derivatives as well as the designation of hedging derivatives with a non-zero fair value at the inception of a hedging relationship

(in thousands of Canadian dollars, except as noted and amounts per share)

11. INCOME TAXES

a. Income tax recognized in statements of earnings

	December 31, 2017	December 31, 2016
Current tax		
Current tax expense in respect of the current year	4,148	2,966
Adjustments recognized in the current year in relation to the current tax expense of prior years	(7)	4
	4,141	2,970
Deferred tax		
Deferred tax expense recognized in the current year	5,463	7,452
Decrease in deferred income tax rates	(2,565)	(4,181)
Adjustments recognized in the current year in relation to the deferred tax of prior years	256	(1,305)
	3,154	1,966
Total income taxes expenses recognized in the current year	7,295	4,936

The following table summarizes the reconciliation of the income tax expense calculated at the Canadian statutory income tax rate and the income tax expense recognized in statements of earnings.

	December 31, 2017	December 31, 2016
Earnings before income taxes	26,963	36,979
Canadian statutory income tax rate	26.6%	26.6%
Income taxes expenses calculated at the statutory rate	7,172	9,836
Items affecting the statutory rate:		
Non-deductible expenses	2,678	1,266
Effect of previously unrecognized tax losses balances used in the year	(322)	(286)
Income taxable at a different rate than the Canadian statutory tax rate	(1,839)	(1,059)
Decrease in deferred income tax rates	(2,565)	(4,181)
Increase in taxable temporary differences in relation to investments in subsidiaries and in joint ventures	710	1,369
Tax on dividends on preferred shares	160	192
Adjustments recognized in the current year in relation to the current tax of prior years	(7)	4
Adjustments recognized in the current year in relation to the deferred tax of prior years	256	(1,305)
Income tax on loss (earnings) allocated to minority interests on non-taxable entities	760	(761)
Others	292	(139)
Income taxes expenses recognized in statements of earnings	7,295	4,936

The tax rate used for 2017 and 2016 reconciliations above is the average combined corporate tax rate payable by corporate entities in Canada on taxable profits under federal and provincials' tax laws. In Canada, the Quebec corporate tax rate is decreasing gradually. The tax rate is reduced from 11.9% in 2016 to 11.8% in 2017 and it will get to 11.5% in 2020. In British-Colombia, an increase from 11.0% to 12.0% will be applicable in 2018. In France, the corporate tax rate continues to decrease. The regular tax rate of 33.33% in 2017 will gradually decline to 25% in 2022.

(in thousands of Canadian dollars, except as noted and amounts per share)

b. Income tax recognized in other comprehensive income

	December 31, 2017	December 31, 2016
Deferred tax		
Arising on income and expenses recognized in other comprehensive income:		
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	60	(91)
Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries	(147)	17
Change in fair value of hedging instruments	4,172	74
Share of change in fair value of hedging instruments of joint venture	201	—
Share of non-controlling interests in change in fair value of hedging instruments	98	(14)
Total income tax recognized directly in other comprehensive income	4,384	(14)

c. Current tax assets and liabilities

	December 31, 2017	December 31, 2016
Current tax assets		
Income tax receivable	—	—
Current tax liabilities		
Income tax payable	3,282	1,292

d. Deferred tax balances

The following is the analysis of deferred tax assets (liabilities) presented in the consolidated statements of financial position:

	December 31, 2017	December 31, 2016
Deferred tax assets	11,873	11,849
Deferred tax liabilities	(215,593)	(176,965)
	(203,720)	(165,116)

(in thousands of Canadian dollars, except as noted and amounts per share)

	As at January 1, 2017	Recognized in statement of earnings	Recognized in other comprehensive income	Recognized in business acquisitions	Net exchange differences	As at December 31, 2017
Deferred tax assets (liabilities) in relation to:						
Property, plant and equipment	(159,667)	1,575	—	(1,011)	(840)	(159,943)
Intangible assets	(115,461)	1,394	—	(34,366)	(2,109)	(150,542)
Project development costs	14,992	(3,589)	—	—	—	11,403
Investments into subsidiaries and in joint ventures	(3,664)	(559)	(232)	—	—	(4,455)
Non-repatriated income from foreign subsidiaries	(1,225)	(22)	—	—	—	(1,247)
Derivative financial instruments	53,549	92	(4,299)	3,262	117	52,721
Long-term debt	(4,327)	(626)	—	2,162	78	(2,713)
Convertible debentures	(486)	128	—	—	—	(358)
Other liabilities	560	(39)	—	—	—	521
Financing fees	(4,268)	468	—	(396)	10	(4,186)
Share-based payment	1,205	176	—	—	—	1,381
	(218,792)	(1,002)	(4,531)	(30,349)	(2,744)	(257,418)
Tax losses carried forward	53,676	(2,152)	147	1,198	829	53,698
	(165,116)	(3,154)	(4,384)	(29,151)	(1,915)	(203,720)

As at December 31, 2017, the Corporation, its subsidiaries and joint ventures have non-capital losses totaling approximately $175,000 that may be applied against future taxable income. The non-capital losses in Canada and the United-States expire gradually between 2031 and 2037. The non-capital losses in France are subject to restrictions over time but have no expiration date.

The Corporation recognized a deferred tax asset on non-capital losses because it is probable that sufficient taxable profit and taxable capital gains will be available from hydroelectric, solar and wind projects currently in operation.

(in thousands of Canadian dollars, except as noted and amounts per share)

	As at January 1, 2016	Recognized in statement of earnings	Recognized in other comprehensive income	Recognized in business acquisitions	Net exchange differences	As at December 31, 2016
Deferred tax assets (liabilities) in relation to:						
Property, plant and equipment	(122,327)	(15,449)	—	(22,511)	620	(159,667)
Intangible assets	(95,119)	11,364	—	(32,734)	1,028	(115,461)
Project development costs	10,717	4,275	—	—	—	14,992
Investments into subsidiaries and in joint ventures	(3,886)	105	117	—	—	(3,664)
Non-repatriated income from foreign subsidiaries	(1,046)	(179)	—	—	—	(1,225)
Derivative financial instruments	55,734	(2,251)	(60)	129	(3)	53,549
Long-term debt	(4,230)	(449)	—	352	—	(4,327)
Convertible debentures	(525)	39	—	—	—	(486)
Other liabilities	540	20	—	—	—	560
Financing fees	(2,692)	(1,576)	—	—	—	(4,268)
Share-based payment	1,020	185	—	—	—	1,205
	(161,814)	(3,916)	57	(54,764)	1,645	(218,792)
Tax losses carried forward	29,239	1,950	(43)	23,409	(879)	53,676
	(132,575)	(1,966)	14	(31,355)	766	(165,116)

(in thousands of Canadian dollars, except as noted and amounts per share)

e. Unrecognized deductible temporary differences, unused tax losses and unused tax credits

	December 31, 2017	December 31, 2016
Tax losses - revenue in nature	4,468	3,551
Tax losses- capital in nature	8,584	10,990
Transaction costs	477	476
	13,529	15,017

The unrecognized tax losses-revenue in nature will expire gradually between 2034 and 2036.

12. EARNINGS PER SHARE

The net earnings per share is computed as follows:

	Year ended December 31	
	2017	2016
Net earnings attributable to owners of the parent	30,007	35,963
Dividends declared on preferred shares	(5,942)	(5,942)
Net earnings available to common shareholders	24,065	30,021
Weighted average number of common shares (in 000s)	108,427	106,883
Basic net earnings per share ($)	0.22	0.28
Weighted average number of common shares (in 000s)	108,427	106,883
Effect of dilutive elements on common shares (in 000s) (a)	820	879
Diluted weighted average number of common shares (in 000s)	109,247	107,762
Diluted net earnings per share ($)	0.22	0.28

a. Stock options for which the exercise price was above the average market price of common shares are excluded from the calculation of diluted weighted average number of shares outstanding.

	Year ended December 31	
	2017	2016
Shares that are excluded from the dilutive elements on common shares that can be issued from (in 000s) :		
Stock options	203	126
Convertible debentures	6,667	6,667

13. KEY MANAGEMENT PERSONNEL COMPENSATION

The following are the expenses that the Corporation recognized for its key management personnel. The members of the Board of Directors as well as the President and CEO, CFO, CIO and all the Senior Vice-Presidents and Vice-Presidents are key management personnel of the Corporation.

	Year ended December 31	
	2017	2016
Salaries and short-term benefits	5,642	6,024
Attendance fees for members of the Board of Directors	700	662
Performance share plan	1,503	1,610
Share-based payment	390	103
	8,235	8,399

14. EMPLOYEE BENEFITS

The expenses that the Corporation recognized for its employee benefits is composed of salaries and short-term benefits. The expenses were included in the following categories:

	Year ended December 31	
	2017	2016
Operating expenses	5,287	4,421
General and administrative	9,815	9,843
Prospective projects expenses	6,942	5,602
Transaction costs	1,538	1,304
Capitalized in Property, plant and equipment	2,306	3,676
	25,888	24,846

15. RESTRICTED CASH AND SHORT-TERM INVESTMENTS

As at	December 31, 2017	December 31, 2016
Restricted cash accounts	24,586	25,424
Restricted proceeds account	27,037	57,362
Debt service payment accounts	7,053	6,956
	58,676	89,742

As part of the Boulder Creek Power LP, Upper Lillooet River Power LP, Kwoiek Creek LP, Northwest Stave LP, Big Silver Creek Power LP, Tretheway Creek Power LP, Mesgig'g Ugju's'n LP, Rougemont 1, Rougemont 2, Vaite, Plan Fleury and Les Renardières credit agreements, the Corporation maintains restricted cash accounts and restricted proceeds accounts. The balance of the loans proceeds are held in restricted proceeds account managed by the lenders and amounts are transferred from time to time into the restricted cash accounts to finance the construction of the projects. The restricted cash accounts are used to pay the current construction costs of the projects and to hold the construction holdbacks amounts that will be released at the end of the construction of the respective projects.

(in thousands of Canadian dollars, except as noted and amounts per share)

In relation with the six run-of-river hydroelectric facilities at Harrison Hydro L.P. (the "Harrison Operating Facilities"), the Corporation maintains debt service payment accounts. The debt service payment accounts require a monthly transfer equal to one-sixth of the next semi-annual bond payments and a monthly transfer equal to one-third of the next quarterly bond payment required on the outstanding junior bonds. Senior and junior loan payments are taken from this account on their due dates.

16. ACCOUNTS RECEIVABLE

As at	December 31, 2017	December 31, 2016
Trade	52,196	23,479
Commodity taxes	25,110	18,980
Investment tax credits	2,418	1,476
Payment receivable for property, plant and equipment	—	49,250
Others	7,776	5,662
	87,500	98,847

Substantially all of the Corporation's trade receivables relate to electricity sold to public utilities including Hydro-Québec, British Columbia Hydro, Hydro One Inc. and its affiliates, Idaho Power Company, Électricité de France and S.I.C.A.E Oise.

Hydro-Québec currently holds a credit rating of Aa2 from Moody's. British Columbia Hydro and Power Authority currently holds a credit rating of Aaa from Moody's. The Ministry of Energy of the Province of Ontario has stated that the Province of Ontario, which currently holds a credit rating of A+ from Standard & Poor's (S&P), will honor Hydro One Inc. and its affiliates obligations under the PPAs to which it is a party. Hydro One Inc. and its affiliates currently holds a credit rating of A from S&P. Idaho Power Company currently has a credit rating of BBB from S&P. Électricité de France currently has a credit rating of A- from S&P.

Commodity taxes and investment tax credits are receivable from governments, mainly in relation with the development and construction of projects. The payment receivable for property, plant and equipment has been received from Hydro-Québec and was related to the substation of the Mesgi'g Ugju's'n wind farm.

The Corporation did not record any allowance for doubtful accounts since, based on its experience, there is a low risk of bad debts. The Corporation does not hold any specific guarantees for its accounts receivable. All accounts receivable are current.

(in thousands of Canadian dollars, except as noted and amounts per share)

17. RESERVE ACCOUNTS

	Hydrology / wind power reserve	Major maintenance reserve	Total
Reserves – As at January 1, 2017	46,311	3,178	49,489
Net (withdrawals from) investments in the reserves	(793)	878	85
Impact of foreign exchange fluctuations	396	—	396
Reserves – end of year	45,914	4,056	49,970
Less: Current portion	—	—	—
Long-term portion	45,914	4,056	49,970

	Hydrology / wind power reserve	Major maintenance reserve	Total
Reserves – As at January 1, 2016	39,724	3,112	42,836
Reserve acquired on business acquisition (Note 5)	8,541	—	8,541
Net (withdrawals from) investments in the reserves	(1,701)	91	(1,610)
Impact of foreign exchange fluctuations	(253)	(25)	(278)
Reserves – end of year	46,311	3,178	49,489
Less: Current portion	—	—	—
Long-term portion	46,311	3,178	49,489

Short-term investments are held at major financial institutions. The Corporation recorded no impairment on these financial instruments since the counterparties have high credit ratings.

The availability of $49,180 ($48,650 in 2016) in the reserve accounts is restricted by credit agreements.

(in thousands of Canadian dollars, except as noted and amounts per share)

18. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2017	3,011	1,613,017	876,569	124,303	426,059	10,830	3,053,789
Additions	4	17,870	12,147	12	61,319	3,677	95,029
Business acquisitions (Note 5)	40	—	340,396	—	122,203	—	462,639
Transfer of assets upon commissioning	—	453,495	156,086	—	(609,581)	—	—
Dispositions	—	(2,001)	(178)	—	—	(95)	(2,274)
Other changes	—	—	3,215	7	—	(23)	3,199
Net foreign exchange differences	—	(524)	22,059	—	—	87	21,622
As at December 31, 2017	3,055	2,081,857	1,410,294	124,322	—	14,476	3,634,004
Accumulated depreciation							
As at January 1, 2017	—	(194,633)	(123,831)	(27,775)	—	(7,543)	(353,782)
Depreciation	—	(37,400)	(47,848)	(5,958)	—	(1,556)	(92,762)
Dispositions	—	1,212	41	—	—	90	1,343
Other changes	—	—	—	—	—	25	25
Net foreign exchange differences	—	205	(801)	—	—	6	(590)
As at December 31, 2017	—	(230,616)	(172,439)	(33,733)	—	(8,978)	(445,766)
Carrying amount as at December 31, 2017	3,055	1,851,241	1,237,855	90,589	—	5,498	3,188,238

All of the property, plant and equipment are given as securities under the respective project financing or for corporate financing.

Additions in the current period include $6,716 of capitalized financing costs incurred prior to their commissioning.

The financing costs related to a specific project financing are entirely capitalized to the specific property, plant and equipment. Financing costs related to the revolving credit facilities are capitalized for the portion of the financing actually used for a specific property, plant and equipment.

The cost of the facilities were reduced by investment tax credits of $3,003 ($3,003 as at December 31, 2016).

(in thousands of Canadian dollars, except as noted and amounts per share)

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2016	2,623	1,427,025	372,038	124,274	531,591	9,194	2,466,745
Additions	—	1,178	522	11	368,503	1,897	372,111
Business acquisitions (Note 5)	392	1,500	218,956	—	—	8	220,856
Transfer of assets upon commissioning	—	183,556	290,479	—	(474,035)	—	—
Other changes	—	—	540	18	—	(263)	295
Net foreign exchange differences	(4)	(242)	(5,966)	—	—	(6)	(6,218)
As at December 31, 2016	3,011	1,613,017	876,569	124,303	426,059	10,830	3,053,789
Accumulated depreciation							
As at January 1, 2016	—	(164,117)	(100,307)	(21,820)	—	(6,279)	(292,523)
Depreciation	—	(30,604)	(23,642)	(5,955)	—	(1,521)	(61,722)
Other changes	—	—	5	—	—	263	268
Net foreign exchange differences	—	88	113	—	—	(6)	195
As at December 31, 2016	—	(194,633)	(123,831)	(27,775)	—	(7,543)	(353,782)
Carrying amount as at December 31, 2016	3,011	1,418,384	752,738	96,528	426,059	3,287	2,700,007

(in thousands of Canadian dollars, except as noted and amounts per share)

19. INTANGIBLE ASSETS

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
Cost					
As at January 1, 2017	545,215	165,489	9,538	—	720,242
Additions	23,041	—	—	—	23,041
Business acquisitions (Note 5)	—	94,249	—	21,423	115,672
Transfer of assets upon commissioning	—	21,423	—	(21,423)	—
Other changes	(5,326)	(1,122)	—	—	(6,448)
Net foreign exchange	(174)	7,822	—	—	7,648
As at December 31, 2017	562,756	287,861	9,538	—	860,155
Accumulated amortization					
As at January 1, 2017	(137,629)	(35,542)	(2,206)	—	(175,377)
Amortization	(20,070)	(16,120)	(477)	—	(36,667)
Other changes	5,326	1,122	—	—	6,448
Net foreign exchange	84	(562)	—	—	(478)
As at December 31, 2017	(152,289)	(51,102)	(2,683)	—	(206,074)
Net value as at December 31, 2017	410,467	236,759	6,855	—	654,081

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
Cost					
As at January 1, 2016	517,089	75,816	9,538	23,240	625,683
Business acquisitions (Note 5)	8,078	95,977	—	—	104,055
Transfer of assets upon commissioning	23,240	—	—	(23,240)	—
Other changes	(3,111)	(3,365)	—	—	(6,476)
Net foreign exchange	(81)	(2,939)	—	—	(3,020)
As at December 31, 2016	545,215	165,489	9,538	—	720,242
Accumulated amortization					
As at January 1, 2016	(122,542)	(29,045)	(1,729)	(96)	(153,412)
Amortization	(18,232)	(9,968)	(477)	96	(28,581)
Other changes	3,111	3,365	—	—	6,476
Net foreign exchange	34	106	—	—	140
As at December 31, 2016	(137,629)	(35,542)	(2,206)	—	(175,377)
Net value as at December 31, 2016	407,586	129,947	7,332	—	544,865

(in thousands of Canadian dollars, except as noted and amounts per share)

20. GOODWILL

Allocation of goodwill to each cash-generating unit is as follows:

As at	December 31, 2017	December 31, 2016
St-Paulin	935	935
Portneuf	4,166	4,166
Chaudière	3,168	3,168
Yonne	6,832	—
Rougemont 1	3,716	—
Rougemont 2	3,480	—
Vaite	4,585	—
Plan Fleury	6,886	—
Renardières	4,812	—
Total Goodwill	38,580	8,269

Changes in the year in the goodwill arise from business acquisitions (see Note 5).

For the years ended December 31, 2017 and 2016, the Corporation conducted annual goodwill impairment tests. Based on the result of these tests, no impairment charge was required.

The recoverable amount of each cash-generating unit is determined based on a value in use calculation which uses cash flow projections based on financial budgets approved by management covering a period extending to the lesser of 50 years or the period for which the Corporation owns its rights on the site and discount rates of 4.1% to 5.4% (5.4% in 2016).

Assumptions used to determine the recoverable amount of assets are the following:

- The discount rate is a weighted average between the consolidated cost of debt and the consolidated cost of equity.
- The expected selling price of electricity once the power purchase agreements are renewed or on the spot market.
- A cash-generating unit is an individual facility.
- The future expected cash flows are based on the budgets before debt service and income tax of each cash-generating unit. The budgets have been built using long-term averages of expected production. These long-term averages approximate actual results.

21. ACCOUNTS PAYABLE AND OTHER PAYABLES

As at	December 31, 2017	December 31, 2016
Trade and other payables	63,487	51,360
Current portion of construction holdbacks	9,104	22,259
Interest payable	15,523	10,754
Commodity taxes	2,918	1,477
	91,032	85,850

(in thousands of Canadian dollars, except as noted and amounts per share)

22. LONG-TERM DEBT

(references to US$ and € are in thousands)

	Interests rate 2017	Maturity	December 31, 2017	December 31, 2016
Revolving credit facilities including LIBOR advances of US$13,900				
a) Innergex	3.03%-4.05%	2022	281,438	189,163
Project Loans				
b) Plan Fleury (€45,411)	1.00%-1.80%	2018-2034	68,353	—
c) Les Renardières (€40,175)	1.05%-1.80%	2018-2034	60,471	—
d) Rougemont 1 (€52,946)	0.54%-0.73%	2018-2035	79,695	—
e) Rougemont 2 (€59,234)	0.47%-0.73%	2018-2035	89,158	—
f) Montagne-Sèche	3.19%	2021	23,360	24,534
g) Rutherford Creek	6.88%	2024	32,061	35,845
h) Valottes (€ 10,934)	1.80%-2.69%	2024-2026	16,458	17,407
i) Ashlu Creek	2.98%	2025	89,387	91,989
j) Sainte-Marguerite	3.30%-8.00%	2025-2064	67,705	71,473
k) Antoigné (€ 5,714)	2.67%	2025	8,601	9,109
l) Longueval (€ 6,724)	1.67%-1.86%	2025	10,121	10,658
m) Porcien (€ 6,895)	1.67%-1.86%	2025	10,378	10,973
n) Innergex Champagne et Innergex Lorraine (€8,775)	7.25%	2025	13,208	—
o) Bois d'Anchat (€ 9,760)	2.25%-3.20%	2025-2030	14,691	14,880
p) Magpie	4.34%-4.37%	2025-2031	52,030	55,304
q) L'Anse-à-Valleau	2.74%	2026	30,490	33,327
r) Fitzsimmons Creek	2.12%	2026	20,230	20,651
s) Montjean (€ 17,534)	1.46%-2.73%	2026-2031	26,392	23,971
t) Theil Rabier (€ 19,520)	1.46%-2.73%	2026-2031	29,381	24,537
u) Mesgi'g Ugju's'n	3.07%-4.28%	2026-2036	257,515	284,931
v) Carleton	3.90%	2027	38,802	42,346
w) Beaumont (€ 22,959)	2.16%-2.63%	2027-2031	34,558	34,598
x) Yonne (€57,351)	1.08%-1.54%	2028-2031	86,325	—
y) Stardale	3.07%	2030	96,563	102,946
z) Cholletz (€ 10,322)	2.64%	2030	15,537	15,799
aa) Vaite (€55,163)	0.54%	2035	83,031	—
bb) Big Silver Creek	4.57%-4.76%	2041-2056	197,223	197,223
cc) Innergex Europe	8.00%	2046	77,957	38,189
dd) Harrison Operating Facilities	3.91%-6.58%	2049	452,513	456,060
ee) Kwoiek Creek	5.08%-10.07%	2052-2054	170,635	172,162
ff) Northwest Stave River	5.30%	2053	71,972	71,972
gg) Tretheway Creek	4.99%	2055	92,916	92,916
hh) Boulder Creek and Upper Lillooet	4.22%-4.46%		491,643	491,643
Other loans with various interest rates		2019	11	13
			2,909,371	2,445,456
Total long-term debt			3,190,809	2,634,619
Deferred financing costs			(33,351)	(27,986)
			3,157,458	2,606,633
Current portion of long-term debt			(109,875)	(99,397)
Long-term portion			3,047,583	2,507,236

22. LONG-TERM DEBT (continued)

a. Revolving credit facilities

On February 21, 2017, the Corporation executed a Fifth Amended and Restated Credit Agreement of its existing $425,000 revolving credit facilities. These amendments give the Corporation flexibility in borrowing in euros using EURIBOR loans. The Corporation also extended its revolving term from 2020 to 2021 to provide greater financing flexibility. On October 31, 2017, the Corporation increased its revolving credit facilities by $50,000 and added a new lender to the syndicate of lenders. It also extended the maturity of its revolving facility from December 2021 to December 2022 to provide greater financial flexibility. As at December 31, 2017, the revolving credit facilities were standing at $475,000.

Moreover, a Letter of Credit Facility of an amount of up to $15,000 guaranteed by Export Development Canada (EDC) was added and put in place. No letter of credit have been issued as of December 31, 2017 under this facility.

As at December 31, 2017, the Bankers' Acceptances ("BA") rate advances and prime rate advances totaling $264,000 along with a LIBOR rate advance of $17,438 (US$13,900) were due under this facility. An amount of $43,658 has been used to secure letters of credit. Thus, the unused and available position of the facility was $149,904. The carrying value of assets of the Corporation and subsidiaries given as securities under this facility totals approximately $484,500.

The revolving credit facilities was renegociated on February 6, 2018, see subsequent events section.

b. Plan Fleury

As part of the acquisition of Plan Fleury and Les Renardières, the Corporation assumed the related loan facilities for a total value of €40,302.

- A €2,554 loan bearing a variable interest rate at EURIBOR+1.8% and fully repayable in 2018. It is a short term bridge financing dedicated to pre-finance relevant Value added taxes expenditures recoverable from the government. Following the acquisition, the debt increased by €4,714.
- A €27,688 loan bearing a fix interest rate at 1.65% for the first 10 years and a variable rate thereafter, repayable in quarterly installments starting in 2019 and maturing in 2032.
- A €5,273 loan bearing a fix interest rate at 1.65% for the first 10 years and a variable rate thereafter, repayable in quarterly installments starting in 2019 and maturing in 2034.
- A €4,145 loan bearing a fix interest rate at 1% for 3 years, repayable in quarterly installments and maturing in 2019. The principal repayments are set to €2,073 for 2018.
- A €642 loan bearing a variable interest rate at EURIBOR+1.8%, repayable in semi annual installments and maturing in 2019. The principal repayments are set to €519 for 2018. Following the acquisition, the debt increased by €395.
- A €1,585 revolving loan facility for a debt service reserve, bearing interest at a variable rate at EURIBOR+1.8%, maturing in 2033. As at December 31, 2017, no funds have been drawn from this facility.

The debt is secured by the assets of Eole de Plan Fleury with a carrying value of approximately €68,700.

c. Les Renardières

As part of the acquisition of Plan Fleury and Les Renardières, the Corporation assumed the related loan facilities for a total value of €35,699.

- A €2,131 loan bearing a variable interest rate at EURIBOR+1.8% and fully repayable in 2018. It is a short term bridge financing dedicated to pre-finance relevant Value added taxes expenditures recoverable from the government. Following the acquisition, the debt increased by €4,288.
- A €24,769 loan bearing a fix interest rate at 1.70% for the first 10 years and a variable rate thereafter, repayable in quarterly installments starting in 2019 and maturing in 2032.
- A €4,394 loan bearing a fix interest rate at 1.70% for the first 10 years and a variable rate thereafter, repayable in quarterly installments starting in 2019 and maturing in 2034.
- A €3,762 loan bearing a fix interest rate at 1.05% for 3 years, repayable in quarterly installments and maturing in 2019. The principal repayments are set to €1,881 for 2018.
- A €643 loan bearing a variable interest rate at EURIBOR+1.8%, repayable in semi annual installments and maturing in 2019. The principal repayments are set to €416 for 2018. Following the acquisition, the debt increased by €188.
- A €1,400 revolving loan facility for a debt service reserve, bearing interest at a variable rate at EURIBOR+1.8%, maturing in 2033. As at December 31, 2017, no funds have been drawn from this facility.

The debt is secured by the assets of Les Renardières with a carrying value of approximately €56,400.

d. Rougemont 1

As part of the Rougemont 1-2 and Vaite Acquisition, the Corporation assumed the related loan facilities for a total of €51,579.

- A €1,592 loan bearing a variable interest rate at EURIBOR +1% and fully repayable in 2018. It is a bridge financing dedicated to the consumer taxes recoverable from the government. Following the acquisition, the debt decreased by a net amount of €1,426.
- A €49,987 loan bearing a variable interest rate at EURIBOR +1.4 % to 1.95%, repayable in semi-annual installments and maturing in 2035. The principal repayments are set to €2,910 for 2018. The loan was accounted for at its fair market value of €50,948 for an effective rate of 0.81%. As at December 31, 2017, the all-in effective interest rate was 1.97% after accounting for the interest swap. Following the acquisition, the debt increased by €3,345.
- A €2,410 revolving loan facility for a debt service reserve, bearing interest at a variable rate at EURIBOR +1.5% to 1.65%, maturing in 2027. As at December 31, 2017, no funds have been drawn from this facility.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed €1,000. As at December 31, 2017 an amount of €700 has been used to secure letter of credits related to the decommissioning guarantee.The debt is secured by the assets of Énergies du Plateau Central with a carrying value of approximately €68,000.

e. Rougemont 2

As part of the Rougemont 1-2 and Vaite Acquisition, the Corporation assumed the related loan facilities for a total of €40,758.

- A €776 loan bearing a variable interest rate at EURIBOR +1% and fully repayable in 2019. It is a bridge financing dedicated to the consumer taxes recoverable from the government. Following the acquisition, the debt decreased by a net amount of €477.
- A €31,096 loan bearing a variable interest rate at EURIBOR + 1.4% to 1.95%, repayable in semi-annual installments and maturing in 2035. The principal repayments are set to €1,647 for 2018. The loan was accounted for at its fair market value of €31,688 for an effective rate of 0.81%. As at December 31, 2017, the all-in effective interest rate was 1.99% after accounting for the interest swap. Following the acquisition, the debt increased by €840.
- A €8,886 loan bearing a variable interest rate at EURIBOR +1.4% to 1.95%, repayable in semi-annual installments and maturing in 2035. The principal repayments are set to €794 for 2018. The loan was accounted for at its fair market value of €9,341 for an effective rate of 0.84%. As at December 31, 2017, the all-in effective interest rate was 1.25% after accounting for the interest swap. Following the acquisition, the debt increased by €17,975.
- A €2,840 revolving loan facility for a debt service reserve, bearing interest at a variable rate at EURIBOR + 1.5% to 1.65%, maturing in 2027. As at December 31, 2017, no funds have been drawn from this facility.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed €1,000. As at December 31, 2017 an amount of €861 has been used to secure letter of credits related to the decommissioning guarantee.The debt is secured by the assets of Énergies du Plateau Central 2 with a carrying value of approximately €79,300.

f. Montagne-Sèche

In May 2014, the Corporation renegotiated the loan to extend the maturity to June 2021. The loan consists of a 7-year term loan, amortized over a 16-year period starting in May 2014. The loan bears interest at the BA rate plus an applicable margin. The principal repayments are variable and set at $1,258 for 2018. As at December 31, 2017, the all-in effective interest rate was 5.97% (5.97% in 2016) after accounting for the interest rate swap.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $445. As at December 31, 2017, an amount of $267 has been used to secure one letter of credit. The loan is secured by the assets of Innergex Montagne-Sèche, L.P. with a carrying value of approximately $32,800.

g. Rutherford Creek

The loan consists of a 20-year fixed rate term loan starting in July 2004 amortized over a 12-year period effective July 1, 2012. This debt is repayable by monthly blended payments of principal and interest totaling $511. The principal repayments are variable and are set at $4,052 for 2018. The loan is secured by the assets of Rutherford Creek Power Limited Partnership, with a carrying value of approximately $77,300.

h. Valottes

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €12,022.

- A €4,749 loan bearing interest at 2.69%, repayable in quarterly installments and maturing in 2024. The principal repayments are set to €505 for 2018.
- A €7,273 loan bearing interest at 5.34%, repayable in quarterly installments and maturing in 2026. The principal repayments are set to €727 for 2018. The term loan was accounted for at its fair market value of €8,502 for an effective rate of 1.80%.

The debt is secured by the assets of Energie des Valottes with a carrying value of approximately €21,100.

i. Ashlu Creek

The loan consists of a 15-year term loan, amortized over a 25-year period starting in September 2010. The loan bears interest at the BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $3,017 for 2018. As at December 31, 2017, the all-in effective interest rate was 6.14% (6.16% in 2016) after accounting for the interest rate swap.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $3,000. As at December 31, 2017 an amount of $1,349 had been used to secure one letter of credit. The loan is secured by the assets of Ashlu Creek hydroelectric facility with a carrying value of approximately $152,200.

j. Sainte-Marguerite

The loan consists of a term loan, bearing interest at a fixed rate of 7.40%, repayable in monthly blended payments of principal and interest totaling $360, increasing over the years and maturing in 2025. The principal repayments for 2018 are set at $3,070. The term loan was accounted for at its fair market value of $37,455 for an effective rate of 3.30%. The loan is secured by the assets of Innergex Sainte-Marguerite L.P. with a carrying value of approximately $132,700.

In 2014, a debenture was issued by Innergex Sainte-Marguerite L.P. to RRMD for a total amount of $42,401. This debenture carries an interest rate of 8.00%; it has no predetermined repayment schedule and matures in 2064. The partner, RRMD, is considered a related party.

k. Antoigné

As part of the Seven French Entities Acquired, the Corporation assumed a €6,964 term loan, bearing interest at 2.67%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €714 for 2018. The loan is secured by the assets of Energie Antoigné with a carrying value of approximately €13,200.

l. Longueval

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €7,881.

- A €6,069 loan bearing interest at 1.86%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €639 for 2018.
- A €1,812 loan bearing interest at 5.73%, repayable in semi-annual installments and maturing in 2025. The principal repayments are set to €156 for 2018. The term loan was accounted for at its fair market value of €2,186 for an effective rate of 1.72%.

The debt is secured by the assets of Eoliennes de Longueval with a carrying value of approximately €14,400.

m. Porcien

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €8,116.

- A €6,069 loan bearing interest at 1.86%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €639 for 2018.

- A €2,047 loan bearing interest at 5.73%, repayable in semi-annual installments and maturing in 2025. The principal repayments are set to €200 for 2018. The term loan was accounted for at its fair market value of €2,454 for an effective rate of 1.67%.

The debt is secured by the assets of Energie du Porcien with a carrying value of approximately €14,700.

n. Financing of two of the French subsidiaries

On February 10, 2017, each of Innergex Champagne S.A.S. and Innergex Lorraine S.A.S. concluded a €4,250 subordinated debt financing with a French Infrastructure fund. The subordinated loans carry an interest rate of 7.25%, have an eight year tenor and their principal will be reimbursed at maturity.

o. Bois d'Anchat

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €11,205.

- A €1,005 loan bearing interest at 3.20%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €156 for 2018.

- A €10,200 loan bearing interest at 2.25%, repayable in quarterly installments and maturing in 2030. The principal repayments are set to €703 for 2018.

The debt is secured by the assets of Société d'Exploitation du Parc Éolien du Bois d'Anchat with a carrying value of approximately €20,900.

p. Magpie

A fixed rate bridge loan was amortized until August 2017. The bridge loan was repayable in monthly blended payments of principal and interest totaling $27.

A debenture was amortized until December 2017. The debenture was repayable by yearly blended payments of principal and interest totaling $400, excluding non-cash implicit interest of $18.

A $3,000 convertible debenture has no predetermined repayment schedule and matures in January 2025. The convertible debenture entitles the municipality to a 30% interest in the facility upon conversion of the debenture on or before January 1, 2025. Early conversion is at the discretion of the Corporation. The municipality is a partner in Magpie L.P. and is considered a related party.

A term loan amortizing until 2031 is repayable in monthly blended payments of principal and interest totaling $379. The principal repayments for the term loan are variable and are set at $1,926 for 2018.

The bridge loan and the term loan are secured by the assets of Magpie L.P. with a carrying value of approximately $93,700.

q. L'Anse-à-Valleau

The loan consists of an 18.5-year term loan starting in December 2007 and amortized over an 18.5-year period. The loan bears interests at the BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $2,939 for 2018. As at December 31, 2017, the all-in effective interest rate was 6.13% (6.03% in 2016) after accounting for the interest rate swap.

The lenders also agreed to make available a credit facility of $1,200 in order to secure letters of credit. As at December 31, 2017, an amount of $705 had been used to secure one letter of credit. The loan is secured by the assets of Innergex AAV, L.P. with a carrying value of approximately $49,200.

r. Fitzsimmons Creek

In December 2016, the maturity of the term loan was extended to November 2026; the loan is amortized over a remaining 25-year period starting in January 2017. The loan advances bear interest at the BA rate plus an applicable margin. The principal repayments are variable and are set at $353 for 2018. As at December 31, 2017, the all-in effective interest rate was 3.59% (3.58% in 2016) after accounting for the interest rate swap.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $150. As at December 31, 2017, an amount of $50 had been used to secure one letter of credit. This debt is secured by the assets of Fitzsimmons Creek Hydro L.P. with a carrying value of approximately $23,500.

s. Montjean

As part of the Two French Entities Acquired in Nouvelle-Aquitaine, the Corporation assumed the related loan facilities for a total value of €23,897.

- A €1,126 loan bearing a variable interest rate at EURIBOR +1.5%. It was a bridge financing dedicated to the consumer taxes and recoverable from the government. The unused and available position of this credit facility was €2,945 at acquisition. This loan was fully repaid in June 2017.
- A €12,680 loan on the credit margin bearing interest at a fixed rate of 1.25% until 2026, after which a variable rate will apply, repayable in quarterly installments and maturing in 2031. The principal repayments are set to €1,000 for 2018. The unused and available position of this credit facility was €2,320 at acquisition and nil as at December 31, 2017. The term loan was accounted for at its fair market value of €11,054 for an effective rate of 1.85%.
- A €4,125 loan bearing interest at a fixed rate of 1.15%, repayable in quarterly installments and maturing in 2026. The principal repayments are set to €413 for 2018. There was no unused and available position on this credit facility. The loan was accounted for at its fair market value of €4,062 for an effective rate of 1.46%.
- A €700 loan facility for a debt service reserve, bearing interest at a fixed rate of 2.00%, repayable in quarterly installments starting in 2022 and maturing in 2031. This loan was accounted for at its fair market value of €675 for an effective rate of 2.73%.

The debt is secured by the assets of Montjean Energies with a carrying value of approximately €29,500.

t. Theil Rabier

As part of the Two French Entities Acquired in Nouvelle-Aquitaine, the Corporation assumed the related loan facilities for a total value of €23,897.

- A €1,234 loan bearing a variable interest rate at EURIBOR +1.5%. It is a bridge financing dedicated to the consumer taxes and recoverable from the government. The unused portion of this credit facility at year-end was €2,838 at acquisition. This loan was fully repaid in June 2017.
- A €12,972 loan bearing interest at a fixed rate of 1.25% until 2026, after which a variable rate will apply until maturity, repayable in quarterly installments and maturing in 2031. The principal repayments are set to €1,000 for 2018. The unused portion of this credit facility was €2,028 at acquisition and nil as at December 31, 2017. The loan was accounted for at its fair market value of €11,345 for an effective rate of 1.84%.
- A €4,125 loan bearing interest at a fixed rate of 1.15%, repayable in quarterly installments and maturing in 2026. The principal repayments are set to €413 for 2018. There was no unused and available position on this credit facility. The loan was accounted for at its fair market value of €4,062 for an effective rate of 1.46%.
- A €700 loan facility for a debt service reserve, bearing interest at a fixed rate of 2.00%, repayable in quarterly installments starting in 2022 and maturing in 2031. This loan was accounted for at its fair market value of €676 for an effective rate of 2.73%.

The debt is secured by the assets of Theil Rabier Energies with a carrying value of approximately €31,700.

u. Mesgig'g Ugju's'n

The construction loan was converted into a term loan in November 2017.

The loan comprises three facilities or tranches:

- A $49,250 floating-rate construction loan carrying a swap-fixed interest rate of 2.41%; fully repaid in 2017 with the proceeds of the scheduled reimbursement by Hydro-Québec for the Mesgi'g Ugju's'n electrical substation;
- A $103,000 floating-rate construction loan carrying a swap-fixed interest rate of 3.54%; converted into a 9.5-year term loan and the principal will be amortized over the term of the loan. The principal repayments are set at $6,592 for 2018;
- A $159,459 construction loan carrying a fixed interest rate of 4.28%; converted into a 19.5-year term loan and the principal will begin to be amortized after the maturity of the 9.5-year term loan. The term loan is repayable in quarterly installments starting in 2026 and maturing in 2036.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $51,284. As at December 31, 2017, an amount of $14,430 had been used to secure two letters of credit. This debt is secured by the assets of Mesgi'g Ugju's'n (MU) Wind Farm L.P. with a carrying value of approximately $298,100.

v. Carleton

The loan consists of a 14-year term loan starting in June 2013 and amortized over a 14-year period. The term loan bears interest at the BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $3,613 for 2018. As at December 31, 2017, the all-in effective interest rate was 5.76% (5.46% in 2016) after accounting for the interest rate swap.

This debt is secured by the assets of Innergex CAR, L.P. with a carrying value of approximately $63,100.

w. Beaumont

As part of the Seven French Entities Acquired, the Corporation assumed three loan facilities for a total value of €25,131.

- A €3,649 loan bearing interest at 3.78%, repayable in quarterly installments and maturing in 2027. The principal repayments are set to €68 for 2018. The term loan was accounted for at its fair market value of €3,999 for an effective rate of 2.16%.
- A €982 loan bearing interest at 2.63%, repayable in quarterly installments and maturing in 2027. The principal repayments are set to €25 for 2018.
- A €20,500 loan bearing interest at 2.42%, repayable in quarterly installments and maturing in 2031. The principal repayments are set to €1,390 for 2018.

The debt is secured by the assets of Eoles Beaumont S.A.S. with a carrying value of approximately €46,900.

x. Yonne

As part of the Yonne Acquisition, the Corporation assumed the related loan facilities for a total of €70,814.

- A €11,350 loan bearing a variable interest rate at 0.93% and fully repaid in the second quarter of 2017. It was a bridge financing dedicated to the consumer taxes recoverable from the government.
- A €14,864 loan bearing a variable interest rate at EURIBOR +1.90% , repayable in quarterly installments and maturing in 2028. The principal repayments are set to €3,342 for 2018. The loan was accounted for at its fair market value of €15,328 for an effective rate of 1.08%.
- A €44,600 loan bearing a variable interest rate at EURIBOR +1.95%, repayable in quarterly installments and maturing in 2031. The principal repayments are set to €324 for 2018. The loan was accounted for at its fair market value of €46,075 for an effective rate of 1.54%. As at December 31, 2017, the all-in effective interest rate was 2.32% after accounting for the interest rate swap.

The debt is secured by the assets of Éoles-Yonne SAS with a carrying value of approximately €101,700.

y. Stardale

On February 22, 2016, Stardale refinanced its long-term debt to increase its borrowing by $12,138 to a total of $109,000. The loan bears interest at the BA rate plus an applicable credit margin. The principal repayments are variable and are set at $6,420 for 2018. As at December 31, 2017, the all-in effective interest rate was 4.97% (5.36% in 2016) after accounting for the interest rate swap.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $5,600. As at December 31, 2017, an amount of $5,600 had been used to secure two letters of credit. The loan is secured by the assets of Stardale L.P. with a carrying value of approximately $101,800.

z. Cholletz

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €11,900.

- A €1,500 loan bearing interest at 1.9%, repayable in quarterly installments. This loan was fully repaid in 2017.
- A €10,400 loan bearing interest at 2.23% until 2026 and at variable rate plus an applicable margin afterwards, repayable in quarterly installments and maturing in 2030. The principal repayments are set to €752 for the 2018.

The debt is secured by the assets of Energie des Cholletz with a carrying value of approximately €20,400.

aa. Vaite

As part of the Rougemont 1-2 and Vaite Acquisition, the Corporation assumed the related loan facilities for a total of €53,545.

- A €552 loan bearing a variable interest rate at EURIBOR +1%. It is a bridge financing dedicated to the consumer taxes recoverable from the government. This loan was fully repaid in 2017.
- A €52,993 loan bearing a variable interest rate at EURIBOR +1.4% to 1.95%, repayable in semi-annual installments and maturing in 2035. The principal repayments are set to €3,244 for 2018. The loan was accounted for at its fair market value of €54,023 for an effective rate of 0.81%. As at December 31, 2017, the all-in effective interest rate was 1.99% after accounting for the interest swap. Following the acquisition, the debt increased by €2,820.
- A €2,520 revolving loan facility for a debt service reserve, bearing interest at a variable rate at EURIBOR +1.5% to 1.65%, maturing in 2027. As at December 31, 2017, no funds have been drawn from this facility.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed €1,000. As at December 31, 2017 an amount of €754 has been used to secure letter of credits related to the decommissioning guarantee.The debt is secured by the assets of Énergies du Réchet with a carrying value of approximately €71,600.

bb. Big Silver Creek

The construction loan was converted into a 39.5-year term loan in January 2017.

The loan comprises three facilities or tranches:

- A $51,012 construction loan carrying a fixed interest rate of 4.57%; in 2017 it was converted into a 25-year term loan and the principal will begin to be amortized over a 22-year period starting in 2019. The term loan is repayable in quarterly installments starting in 2019 and maturing in 2041;
- A $128,311 construction loan carrying a fixed interest rate of 4.76%; in 2017 it was converted into a 39.5-year term loan and the principal will be amortized after the 25-year term loan reaches maturity. The term loan is repayable in quarterly installments starting in 2042 and maturing in 2056;
- A $17,900 construction loan carrying a fixed interest rate of 4.76%; in 2017 it was converted into a 39.5-year term loan and its principal will be reimbursed at maturity in 2056.

This debt is secured by the assets of Big Silver Creek Power L.P. with a carrying value of approximately $212,600.

cc. Innergex Europe (2015) Limited Partnership

Following the acquisitions in France, a debenture was issued to the other partner for proceeds of $38,189 in 2016 and additional proceeds of $39,768 in 2017 for a total of $77,957. This debenture carries an interest rate of 8.00% compounded yearly and is payable quarterly if funds are available. The debenture will be repayable in full in 2046. The partner is considered a related party.

The Corporation invested a total of $87,227 in 2016 and additional amounts of $90,832 in 2017 for a total of $178,059 in preferred units of Innergex Europe (2015) Limited Partnership which carry a preferred return rate of 8.00% compounded yearly and payable at the same time as the debenture. The preferred units are eliminated into the consolidation process.

dd. Harrison Operating Facilities

The Harrison Operating Facilities Senior Real Return bond bears interest at 2.96% adjusted by an inflation ratio as well as an inflation compensation interest factor. Both inflation adjustments are based on the All-items Consumer Price Index for Canada (“CPI”), which is not seasonally adjusted. Payments on this bond are due semi-annually and the bond matures in June 2049. Semi-annual payments are $5,790 before CPI adjustment ($6,787 including CPI adjustment in 2017). In December 2031, the payment amount decreases to $4,481 before CPI adjustment, where it remains until maturity. For 2018, the principal repayments are set at $6,276.

The Harrison Operating Facilities Senior Fixed Rate bond bears interest at 6.61%. Payments on this bond are due semi-annually with the bond maturing in September 2049. Semi-annual payments amount to $8,072. In September 2031, the payment amount decreases to $6,724, where it remains until maturity. For 2018, the principal repayments are set at $3,658.

The Harrison Operating Facilities Junior Real Return Rate bond bears interest at 4.27% adjusted by an inflation ratio and an inflation compensation interest factor. Both inflation adjustments are based on the CPI, which is not seasonally adjusted. Payments on this bond are due quarterly and the bond matures in September 2049. Quarterly interest payments amount to $389 before CPI adjustment ($456 including CPI adjustment in 2017). Principal repayment are set at $480 for 2018.

The bonds are secured by the Harrison Operating Facilities. The carrying value of the property and assets of the Harrison Operating Facilities totals approximately $610,000.

	Senior Real Return Bond	Senior Fixed Rate Bond	Junior Real Return Bond	Total
Balance – January 1, 2017	222,645	204,640	28,775	456,060
Inflation compensation interest	3,472	—	438	3,910
Principal repayment	(6,069)	(3,463)	(346)	(9,878)
Amortization of revaluation	1,367	957	97	2,421
Balance – December 31, 2017	221,415	202,134	28,964	452,513

The increase in inflation compensation interest is a result of the CPI rate change over the reference period.

ee. Kwoiek Creek

The $168,500 construction term loan bearing fixed interest rate of 5.08% was converted into a 37-year term loan in February 2015 and amortized over a 36-year period starting in January 2017. The term loan is repayable in quarterly installments. The principal repayments are variable and set at $1,592 for 2018. The loan is secured by the assets of Kwoiek Creek Resources L.P. with a carrying value of approximately $179,558

The Corporation's partner in the Kwoiek Creek project made a $3,662 loan to Kwoiek Creek Resources L.P. Under the project agreements, both partners can participate in the project financing. The loan bears a fixed interest rate of 10.07%. The partner is considered a related party.

ff. Northwest Stave River

The loan consists of a 38-year term loan starting in February 2015 and amortized over a 35-year period starting in 2020. The term loan is repayable in semi-annual installments starting in 2020 and maturing in 2053. The loan is secured by the assets of Northwest Stave River L.P. with a carrying value of approximately $79,100.

gg. Tretheway Creek

The construction loan bearing fixed interest rate of 4.99% was converted into a 39-year term loan in April 2016 and amortized over a 35-year period starting in 2020. The term loan is repayable in semi-annual installments starting in 2020 and maturing in 2055. The loan is secured by the assets of Tretheway L.P. with a carrying value of approximately $106,000.

hh. Boulder Creek and Upper Lillooet River

On March 17, 2015, Boulder Creek Power Limited Partnership and Upper Lillooet River Power Limited Partnership jointly closed a $491,643 non-recourse construction and term project financing for the Boulder Creek and Upper Lillooet River run-of-river hydroelectric projects.

The loan comprises three facilities or tranches:
- A $191,643 construction loan carrying a fixed interest rate of 4.22%; following the start of the facilities' commercial operation, it will convert into a 25-year term loan and the principal will be amortized over a 20-year period, starting in the sixth year.
- A $250,000 construction loan carrying a fixed interest rate of 4.46%; following the start of the facilities' commercial operation, it will convert into a 40-year term loan and the principal will begin to be amortized after the 25-year term loan's maturity.
- A $50,000 construction loan carrying a fixed interest rate of 4.46%; following the start of the facilities' commercial operation, it will convert into a 40-year term loan and its principal will be reimbursed at maturity.

This debt is secured by the assets of Boulder Creek Power L.P. and Upper Lillooet River Power L.P. with a carrying value of approximately $512,800.

(in thousands of Canadian dollars, except as noted and amounts per share)

Principal repayments

The principal repayments for the next years, excluding the revaluations, will be as follows:

	Principal repayments			
	Revolving credit facilities	Project loans	Amortization of revaluation	Long-term debt
2018	—	109,539	336	109,875
2019	—	87,716	140	87,856
2020	—	93,691	(24)	93,667
2021	—	105,825	(207)	105,618
2022	281,438	108,230	(410)	389,258
Thereafter	—	2,440,888	(36,353)	2,404,535
	281,438	2,945,889	(36,518)	3,190,809

(in thousands of Canadian dollars, except as noted and amounts per share)

23. OTHER LIABILITIES

Other liabilities, including amounts shown in current liabilities, consist of contingent considerations, asset retirement obligations, interests payable on Innergex Sainte-Marguerite, S.E.C. ("SM S.E.C.") debenture relating to the Corporation's facilities and the future ownership rights.

	Contingent considerations	Asset retirement obligations	Interests payable on SM S.E.C. debenture	Future ownership rights	Total
As at January 1, 2017	2,949	15,256	9,256	—	27,461
Liability assumed as part of the business acquisitions (note 5)	—	12,060	—	—	12,060
New obligations	—	8,604	—	23,041	31,645
Interest expense included in finance cost	—	—	4,202	—	4,202
Accretion expense included in finance cost	128	656	—	880	1,664
Gain on contingent considerations	(881)	—	—	—	(881)
Revisions in estimated cash flows	—	3,220	—	—	3,220
Payment of contingent considerations	(246)	—	—	—	(246)
Impact of foreign exchange fluctuations	—	882	—	—	882
As at December 31, 2017	1,950	40,678	13,458	23,921	80,007
Current portion of other liabilities	(500)	—	—	—	(500)
Long-term portion of other liabilities	1,450	40,678	13,458	23,921	79,507

	Contingent considerations	Asset retirement obligations	Interests payable on SM S.E.C. debenture	Total
As at January 1, 2016	2,047	6,269	5,359	13,675
Liability assumed as part of the business acquisition (note 5)	—	6,466	—	6,466
New obligations	—	1,687	—	1,687
Interest expense included in finance cost	—	—	3,897	3,897
Accretion expense included in finance cost	102	449	—	551
Loss on contingent considerations	800	—	—	800
Revisions in estimated cash flows	—	563	—	563
Impact of foreign exchange fluctuations	—	(178)	—	(178)
As at December 31, 2016	2,949	15,256	9,256	27,461
Current portion of other liabilities	(495)	—	—	(495)
Long-term portion of other liabilities	2,454	15,256	9,256	26,966

a. Contingent considerations

An acquisition realized in 2011 provides for the potential payment of additional amounts to the vendors over a period commencing on the acquisition date and ending in 2056. The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. The maximum aggregate amount of all deferred payments under this acquisition is limited to a present value amount of $35,000 as at the acquisition date. In connection with the Magpie Acquisition, the Corporation assumed an obligation to pay contingent consideration to the Minganie Regional County Municipality until the convertible debenture issued by Magpie L.P. is converted. Upon conversion, the Minganie Regional County Municipality will be entitled to a participation of 30% in Magpie L.P.

(in thousands of Canadian dollars, except as noted and amounts per share)

b. Asset retirement obligations

Asset retirement obligations primarily arise from obligations to retire wind farms and the solar facility upon expiry of the site leases. The wind farm facilities and solar facility were constructed on sites held under leases expiring at least 25 years after the signing date. The Corporation estimates that the undiscounted value of the payments required for settling the obligations over a 25-year period will be as follows:

Year of expected payments	
2031	2,592
2032	2,466
2033	2,748
2034	2,952
2035	3,028
2036	1,542
2037	6,243
2039	4,602
2040	1,858
2041	11,286
2042	32,921
	72,238

The cash flows were discounted at rates between 1.94% to 4.45% as at December 31, 2017 (4.29% to 4.61% in 2016) to determine the obligations.

c. Interests payable on debentures

In connection with the acquisition of the Sainte-Marguerite facility in 2014, RRMD subscribed to a debenture issued by SM S.E.C. for a total amount of $42,401. This debenture carries an interest rate of 8.00%, has no predetermined repayment schedule and matures in 2064. Unpaid interests are compounded and are recorded in other long-term liabilities.

d. Future ownership rights

Other liabilities, includes various liabilities related to future ownership rights owned by First Nations for the Upper Lillooet River, Boulder Creek, Big Silver Creek and Tretheway Creek facilities, the counterpart of which is capitalized into the intangible assets.

24. CONVERTIBLE DEBENTURES

On August 10, 2015, the Corporation issued an aggregate principal amount of $100,000 of 4.25% convertible debentures at a price of a thousand dollars per convertible debenture, bearing interest at a rate of 4.25% per annum, payable semi-annually on August 31 and February 28 each year, commencing on February 28, 2016. The convertible debentures will be convertible at the holder's option into common shares of the Corporation at a conversion price of $15.00 per share, representing a conversion rate of 66.6667 common shares per each thousand dollars of principal amount of convertible debentures. The convertible debentures will mature on August 31, 2020 and will not be redeemable before August 31, 2018, except in certain limited circumstances. On or after August 31, 2018, and before August 31, 2019, Innergex may redeem the Debentures at par plus accrued and unpaid interest, in certain circumstances. On or after August 31, 2019, Innergex may redeem the debentures at par plus accrued and unpaid interest.

The convertible debentures are subordinated to all other indebtedness of the Corporation.

The liability portion is being accreted such that the liability at maturity will equal the face value less prior conversions if any.

(in thousands of Canadian dollars, except as noted and amounts per share)

25. SHAREHOLDERS' CAPITAL

Authorized

The authorized capital of the Corporation consists of an unlimited number of common shares and an unlimited number of preferred shares, non-voting, retractable and redeemable. This includes up to 3,400,000 Cumulative Rate Reset Preferred Shares, Series A (the "Series A Preferred Shares"), up to 3,400,000 Cumulative Floating Rate Preferred Shares, Series B (the "Series B Preferred Shares") and up to 2,000,000 Cumulative Redeemable Fixed Rate Preferred Shares, Series C (the "Series C Preferred Shares").

a) Common shares

The change in the number of common shares was as follows as at:

As at	December 31, 2017	December 31, 2016
Issued and fully paid		
Beginning of the year	108,181,592	103,938,636
Common shares issued on private placement	—	3,906,250
Common shares issued through dividend reinvestment plan	361,195	242,706
Common shares options exercised	121,378	94,000
Buyback of common shares	(56,082)	—
End of year	108,608,083	108,181,592
Held in trust under the PSP plan		
Beginning of the year	—	—
Purchased	(273,762)	—
End of year	(273,762)	—
Common shares outstanding at end of the year	108,334,321	108,181,592

Buyback of common shares

On August 15, 2017, Innergex announced that it has received approval from the Toronto Stock Exchange (TSX) to proceed with a normal course issuer bid on its common shares (the Bid).

Under the Bid, the Corporation may purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.84% of the 108,640,790 issued and outstanding common share of the Corporation as at August 14, 2017. The Bid commenced on August 17, 2017 and will terminate on August 16, 2018. Up to December 31, 2017, 56,082 common shares have been purchased and cancelled at an average price of $13.85.

In March 2016, the Corporation announced the approval from the Toronto Stock Exchange to renew its normal course issuer bid. Under the bid, the Corporation was entitled to purchase for cancellation up to 2,000,000 of its common shares. No common shares have been purchased and cancelled in 2016.

b) Contributed surplus from reduction of capital account on common shares

A special resolution to approve the reduction of the legal stated capital account maintained in respect of the common shares of the Corporation, without any payment or distribution to the shareholders was adopted on May 9, 2017. This resulted in a decrease of the shareholders' capital account and an equivalent increase of the contributed surplus from reduction of capital on common shares account.

(in thousands of Canadian dollars, except as noted and amounts per share)

c) Preferred shares

Series A Preferred Shares

On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at $25.00 per share for aggregate gross proceeds of $85,000. The holders of Series A Preferred Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends are payable quarterly on the 15th day of January, April, July and October in each year. For the initial five-year period to, but excluding January 15, 2016 (the “Initial Fixed Rate Period”), the dividends were payable at an annual rate equal to $1.25 per share. The annual dividend rate for the five-year period starting January 15, 2016, equal $0.902 per share.

For each five-year period after the Initial Fixed Rate Period (each a ”Subsequent Fixed Rate Period”), the holders of the Series A Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series A Preferred Share equal to the sum of the yield on a Government of Canada bond with a five-year term to maturity on the applicable fixed rate calculation date, plus 2.79% applicable to such Subsequent Fixed Rate Period multiplied by $25.00.

Each holder of Series A Preferred Shares will have the right, at its option, to convert all or any of its Series A Preferred Shares into the Series B Preferred Shares of the Corporation on the basis of one Series B Preferred Share for each Series A Preferred Share converted, subject to certain conditions, on January 15, 2016, and on January 15 every five years thereafter. The holders of Series B Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series B Preferred Share equal to the Treasury Bill rate for the preceding quarterly period plus 2.79% per annum determined on the 30th day prior to the first day of the applicable quarterly floating rate period multiplied by $25.00.

The Series A Preferred Shares were not redeemable by the Corporation prior to January 15, 2016. None were redeemed at that date. The next redemption date is January 15, 2021, and on January 15 every five years thereafter, at which time, the Corporation may, at its option, redeem all or any number of the outstanding Series A Preferred Shares.

Series C Preferred Shares

On December 11, 2012, the Corporation issued a total of 2,000,000 Series C Preferred Shares at $25.00 per share for aggregate gross proceeds of $50,000. Holders of the Series C Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends as and when declared by the Corporation's Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.4375 per share. The Series C Preferred Shares were not redeemable by the Corporation prior to January 15, 2018. The Series C Preferred Shares do not have a fixed maturity date and are not redeemable at the option of the holders.

d) Share-based payment

Stock option

The Corporation has a stock option plan . The share-based payments expense is accounted under fair value method. In accordance with this method, the stock options are measured at the fair value of the equity instruments at the date of grant.

The Corporation has a stock option plan providing for the granting of options by the Board of Directors to employees, officers, directors and certain consultants of the Corporation and its subsidiaries to purchase common shares. Options granted under the stock option plan will have an exercise price of not less than the market price of the common shares at the date of grant of the option, calculated as the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

The maximum number of common shares of the Corporation available for issuance pursuant to options granted under the stock option plan is 4,064,123. Any common shares subject to an option that expires or terminates without having been fully exercised may be subject to a further option. The number of common shares issuable to non-executive directors of the Corporation under the stock option plan cannot at any time exceed 1% of the issued and outstanding common shares.

Options must be exercised during a period established by the Board of Directors, which may not be greater than 10 years after the date of grant. Options granted under the stock option plan vest in equal amounts on a yearly basis over a period of four to five years following the grant date.

During 2017, 752,000 share options have been exercised at $11.00 per share resulting in 121,378 common share issued cashless. The differences between the 752,000 options exercised and the 121,378 shares issued are the result of the exercise of the options without disbursement by the holders and the withholding of deductions at source by the Corporation as authorized by the option plan and the Board of directors.

Also 77,167 share options were granted during the year. The options granted under the stock option plan vest in equal amounts on a yearly basis over a period of four years following the grant date. Options must be exercised before August 2024 at an exercise price of $14.52.

The following table summarizes outstanding stock options of the Corporation as at December 31, 2017 and 2016:

	December 31, 2017		December 31, 2016	
	Number of options (000's)	Weighted average exercise price ($)	Number of options (000's)	Weighted average exercise price ($)
Outstanding - beginning of year	3,457	10.23	3,425	10.09
Granted during the year	77	14.52	126	14.65
Exercised during the year	(752)	11.00	(94)	11
Canceled during the year	—	—	—	—
Outstanding - end of year	2,782	10.14	3,457	10.23
Options exercisable - end of year	2,512	9.80	3,034	10.03

The following options were outstanding and exercisable as at December 31, 2017:

Year of granting	Number of options outstanding (000's)	Exercise price ($)	Number of options exercisable (000's)	Year of maturity
2011	770	9.88	770	2018
2012	397	10.70	397	2019
2010	618	8.75	618	2020
2013	397	9.13	397	2020
2014	397	10.96	298	2021
2016	126	14.65	32	2023
2017	77	14.52	—	2024
	2,782		2,512	

The Corporation applies the fair value method of accounting for options granted to senior management, which is estimated using the Black-Scholes option-pricing model. Share-based payments are expensed and a credit is made to the share-based payment account in the equity of the Corporation to account for the options granted.

The following assumptions were used to estimate the fair value of the options issued to grantees during the year:

	December 31, 2017
Risk-free interest rate	1.67%
Expected annual dividend per common share	$0.66
Expected life of options	6 years
Expected volatility	19.53%
Fair value of options granted	$1.40

For the purpose of compensation expense, stock-based compensation is amortized to expenses on a straight-line basis over the vesting period of a maximum of five years. The weighted average contractual life of the outstanding stock options is five years. Expected volatility is estimated by considering historic average share price volatility.

e) Dividend Reinvestment Plan ("DRIP")

(in thousands of Canadian dollars, except as noted and amounts per share)

The Corporation implemented a DRIP for its shareholders. The plan allows eligible common shareholders the opportunity to reinvest a portion or all of the dividends they receive to purchase additional common shares of the Corporation, without paying fees such as brokerage commissions and service charges. Shares will either be purchased on the open market or issued from treasury.

f) Performance Share Plan and Deferred Share Unit Plan

Performance Share Plan (the "PSP Plan")

The goal of the PSP Plan is to motivate the executive officers to create long-term economic value for the Corporation and its shareholders. This portion of the Equity-Based Incentive Plan focuses executive officers on delivering business performance over the next three years against the total shareholder value. The award is paid out at the end of the three years, depending on how well the Corporation performed against targets set at the beginning of the three-year period.

The vesting date of the performance share rights is determined on the grant date which shall not exceed three (3) years thereafter. The payouts are made in shares, so the value goes up or down based on stock price performance from the beginning of the grant. On the vesting date, each performance share right entitles its holder to one Common Share of the Corporation with all the reinvested dividends accrued thereon from the grant date, such dividend being either paid in cash, in shares or in a combination of both at the sole discretion of the Corporation.

The Corporation's Deferred Share Unit Plan

Under the Corporation's Deferred Share Unit Plan (the "DSU Plan"), Directors and officers may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation. A DSU is a unit that has a value based upon the value of one Common Share. When a dividend is paid on Common Shares, the Director's DSU account is credited with additional DSUs equivalent to the dividend paid.

DSUs cannot be redeemed for cash until the Director leaves the Board or the officer leaves. DSUs are not shares, cannot be converted to shares, and do not carry voting rights. DSUs received by Directors and officers in lieu of cash compensation and held by them represent an at-risk investment in the Corporation. The value of DSUs is based on the value of the Common Shares, and therefore is not guaranteed.

The number of PSP and DSU has varied as follows, for the year ended:

	December 31, 2017		December 31, 2016	
(in 000s)	PSP	DSU	PSP	DSU
Balance beginning of year	325	4	263	—
Granted during the year	135	23	122	4
Paid out during the year	(113)	—	(75)	—
Dividend reinvestment during the year	21	1	15	—
Balance end of year	368	28	325	4

From time to time, the Corporation provides instructions to a trustee under the terms of a Trust Agreement to purchase common shares of the Corporation in the open market in connection with the PSP plan. These shares are held in Trust for the benefit of the beneficiaries until the PSPs become vested or cancelled. The cost of these purchases has been deducted from share capital.

A compensation expense of $1,695 was recorded during the year ended December 31, 2017 with respect to the PSP and DSU plan (a compensation expense of $1,610 was recorded during the year ended December 31, 2016).

26 ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries	Net currency translation reserve	Cash flow hedge interest rate risk	Share of cash flow hedge interest rate risk of joint venture	Total
Balance as at January 1, 2017	1,094	(1,290)	(196)	(1,596)	49	(1,743)
Exchange differences on translation of foreign operations	27	—	27	—	—	27
Hedging gain of the reporting period	—	69	69	15,047	815	15,931
Related deferred tax	(60)	147	87	(4,172)	(201)	(4,286)
Balance as at December 31, 2017	1,061	(1,074)	(13)	9,279	663	9,929

	Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries	Net currency translation reserve	Cash flow hedge interest rate risk	Share of cash flow hedge interest rate risk of joint venture	Total
Balance as at January 1, 2016	1,875	(1,569)	306	(1,930)	48	(1,576)
Exchange differences on translation of foreign operations	(872)	—	(872)	—	—	(872)
Hedging gain of the reporting period	—	296	296	408	1	705
Related deferred tax	91	(17)	74	(74)	—	—
Balance as at December 31, 2016	1,094	(1,290)	(196)	(1,596)	49	(1,743)

(in thousands of Canadian dollars, except as noted and amounts per share)

27. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Year ended December 31	
	2017	2016
Accounts receivable and income tax receivable	59,271	(46,109)
Prepaid and others	(1,844)	156
Accounts payable and other payables and income tax payable	(33,645)	(10,489)
	23,782	(56,442)

b. Additional information

	Year ended December 31	
	2017	2016
Interest paid (including $6,882 capitalized interest ($37,838 in 2016))	132,707	87,574
Non-cash transactions		
in unpaid property, plant and equipment	(49,845)	19,596
in unpaid other liabilities	23,041	—
in unpaid intangible assets	(23,041)	—
in common shares issued through share options exercised	(101)	(78)
variation in discounted rates in asset retirement obligations	3,220	563
in common shares issued through dividend reinvestment plan	(5,135)	(3,209)
loans to partners in exchange of non-controlling interests in subsidiaries	(4)	(27)

c. Changes in liabilities arising from financing activities

	Year ended December 31	
	2017	2016
Long-term debt at beginning of the period	2,606,633	2,215,433
Increase of long-term debt	668,856	872,247
Repayment of long-term debt	(576,187)	(657,207)
Payment of deferred financing costs	(1,161)	(2,680)
Business acquisitions (Note 5)	432,351	178,362
Other changes	7,677	5,815
Net foreign exchange differences	19,289	(5,337)
Long-term debt at end of the period	3,157,458	2,606,633

(in thousands of Canadian dollars, except as noted and amounts per share)

28. SUBSIDIARIES

Details of non-wholly-owned subsidiaries that have non-controlling interests

The table below shows details of non-wholly-owned subsidiaries of the Corporation:

Name of subsidiaries	Place of creation and operation	Proportion of ownership interests and voting rights held by non-controlling interests		Earnings (loss) allocated to non-controlling interests for the year ended		Non-controlling interests (deficit)	
		Dec. 31, 2017	Dec. 31, 2016	Dec. 31, 2017	Dec. 31, 2016	Dec. 31, 2017	Dec. 31, 2016
Harrison Hydro L.P. and its subsidiaries	Canada	49.99%	49.99%	(2,828)	3,063	52,884	61,710
Creek Power Inc. and its subsidiaries	Canada	33.33%	33.33%	(4,533)	(1,531)	(27,065)	(22,687)
Kwoiek Creek Resources, L.P. (1)	Canada	50.00%	50.00%	(445)	(352)	(11,169)	(10,724)
Mesgi'g Ugju's'n (MU) Wind Farm L.P. (1)	Canada	50.00%	50.00%	6,030	(303)	(3,699)	(9,167)
Innergex Sainte-Marguerite, S.E.C.	Canada	49.99%	49.99%	(1,052)	(2,144)	(6,614)	(5,562)
Innergex Europe (2015) Limited Partnership and its subsidiaries (2)	Canada/ Europe	30.45%	30.45%	(7,168)	(2,708)	10,561	779
Others	Canada	Various	Various	(343)	55	22	363
				(10,339)	(3,920)	14,920	14,712

1.The Corporation owns more than 50% of the economic interest in the subsidiary.
2.Period of 261 days in 2016.

(in thousands of Canadian dollars, except as noted and amounts per share)

Summarized financial information in respect of each of the Corporation's subsidiaries that has material non-controlling interests is set out below. The summarized financial information below represents amounts before intragroup eliminations.

Harrison Hydro L.P. and its subsidiaries

As at	December 31, 2017	December 31, 2016
Summary Statements of Financial Position		
Current assets	13,376	22,416
Non-current assets	601,105	615,937
	614,481	638,353
Current liabilities	17,163	17,847
Non-current liabilities	453,647	458,037
Equity attributable to owners	90,787	100,759
Non-controlling interests	52,884	61,710
	614,481	638,353

	Year ended December 31	
	2017	2016
Summary Statements of Earnings and Comprehensive income (loss)		
Revenues	50,891	60,039
Expenses	57,689	55,057
Net (loss) earnings and comprehensive (loss) income	(6,798)	4,982
Net (loss) earnings and comprehensive (loss) income attributable to:		
Owners of the parent	(3,970)	1,919
Non-controlling interests	(2,828)	3,063
	(6,798)	4,982
Summary Statements of Cash Flows		
Net cash inflow from operating activities	15,486	29,458
Net cash outflow from financing activities	(21,878)	(22,581)
Net cash outflow from investing activities	(1,287)	(98)
Net (decrease) increase in cash and cash equivalents	(7,679)	6,779
Distributions paid to non-controlling interests	5,998	6,748

(in thousands of Canadian dollars, except as noted and amounts per share)

Creek Power Inc. and its subsidiaries

As at	December 31, 2017	December 31, 2016
Summary Statements of Financial Position		
Current assets	36,422	82,759
Non-current assets	542,988	492,414
	579,410	575,173
Current liabilities	53,658	48,853
Non-current liabilities [1]	618,205	605,658
Deficit attributable to owners	(65,388)	(56,651)
Non-controlling interest deficit	(27,065)	(22,687)
	579,410	575,173

1. Non-current liabilities include $98,443 of preferred units own by Innergex

	Year ended December 31	
	2017	2016
Summary Statements of Earnings and Comprehensive loss		
Revenues	27,882	3,413
Expenses [1]	41,462	7,972
Net loss	(13,580)	(4,559)
Other comprehensive income	465	26
Total comprehensive loss	(13,115)	(4,533)
Net loss attributable to:		
Owners of the parent	(9,047)	(3,028)
Non-controlling interest	(4,533)	(1,531)
	(13,580)	(4,559)
Total comprehensive loss attributable to:		
Owners of the parent	(8,737)	(3,011)
Non-controlling interest	(4,378)	(1,522)
	(13,115)	(4,533)
Summary Statements of Cash Flows		
Net cash inflow from operating activities	5,967	92
Net cash inflow from financing activities	12,733	44,774
Net cash outflow from investing activities	(18,359)	(44,283)
Net increase in cash and cash equivalents	341	583
Distributions paid to non-controlling interests	—	—

1. Expenses include $11,196 of preferred return payable to Innergex on the $98,443 preferred units. Excluding these elements, the Net loss would have been $2,384.

(in thousands of Canadian dollars, except as noted and amounts per share)

Kwoiek Creek Resources L.P.

As at	December 31, 2017	December 31, 2016
Summary Statements of Financial Position		
Current assets	7,335	8,949
Non-current assets	172,223	175,049
	179,558	183,998
Current liabilities	7,919	9,964
Non-current liabilities [1]	193,480	194,985
Deficit attributable to owners	(10,672)	(10,227)
Non-controlling interest deficit	(11,169)	(10,724)
	179,558	183,998

1. Non-current liabilities include $39,752 of preferred units own by Innergex and $3,662 subordinated debt own by a partner

	Year ended December 31	
	2017	2016
Summary Statements of Earnings and Comprehensive loss		
Revenues	19,016	19,840
Expenses [1]	19,906	20,544
Net loss and comprehensive loss	(890)	(704)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(445)	(352)
Non-controlling interest	(445)	(352)
	(890)	(704)
Summary Statements of Cash Flows		
Net cash (outflow) inflow from operating activities	(97)	1,967
Net cash outflow from financing activities	(1,530)	—
Net cash outflow from investing activities	(175)	(113)
Net (decrease) increase in cash and cash equivalents	(1,802)	1,854
Distributions paid to non-controlling interests	—	—

1. Expenses include $4,185 of preferred return payable to Innergex on the $39,752 preferred units and on the $3,662 subordinated debt payable to a partner. Excluding these elements, the Net earnings would have been $3,294.

(in thousands of Canadian dollars, except as noted and amounts per share)

Mesgi'g Ugju's'n (MU) Wind Farm L.P.

As at	December 31, 2017	December 31, 2016
Summary Statements of Financial Position		
Current assets	21,727	64,843
Non-current assets	283,271	294,918
	304,998	359,761
Current liabilities	16,004	59,360
Non-current liabilities	247,867	264,582
Equity attributable to owners	44,826	44,986
Non-controlling interest deficit	(3,699)	(9,167)
	304,998	359,761

	Year ended December 31	
	2017	2016
Summary Statements of Earnings and Comprehensive loss		
Revenues	51,845	1,024
Expenses	30,020	2,121
Net earnings (loss)	21,825	(1,097)
Other comprehensive income (loss)	3,246	(1,643)
Total comprehensive income (loss)	25,071	(2,740)
Net earnings (loss) attributable to:		
Owners of the parent	15,795	(794)
Non-controlling interest	6,030	(303)
	21,825	(1,097)
Total comprehensive income (loss) attributable to:		
Owners of the parent	18,144	(1,955)
Non-controlling interest	6,927	(785)
	25,071	(2,740)
Summary Statements of Cash Flows		
Net cash inflow (outflow) from operating activities	77,324	(54,473)
Net cash (outflow) inflow from financing activities	(47,379)	124,368
Net cash outflow from investing activities	(32,345)	(63,787)
Net (decrease) increase in cash and cash equivalents	(2,400)	6,108
Distributions paid to non-controlling interests	—	—

(in thousands of Canadian dollars, except as noted and amounts per share)

Innergex Sainte-Marguerite, S.E.C.

As at	December 31, 2017	December 31, 2016
Summary Statements of Financial Position		
Current assets	2,794	2,344
Non-current assets	129,614	132,351
	132,408	134,695
Current liabilities	8,085	8,654
Non-current liabilities [1]	121,067	120,681
Equity attributable to owners	9,870	10,922
Non-controlling interest deficit	(6,614)	(5,562)
	132,408	134,695

1. Non-current liabilities include $43,720 of preferred units own by Innergex

	Year ended December 31	
	2017	2016
Summary Statements of Earnings and Comprehensive loss		
Revenues	12,755	10,666
Expenses [1]	14,859	14,955
Net loss and comprehensive loss	(2,104)	(4,289)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(1,052)	(2,145)
Non-controlling interest	(1,052)	(2,144)
	(2,104)	(4,289)
Summary Statements of Cash Flows		
Net cash inflow from operating activities	3,768	3,149
Net cash outflow from financing activities	(2,928)	(2,605)
Net cash outflow from investing activities	(217)	(441)
Net increase in cash and cash equivalents	623	103
Distributions paid to non-controlling interests	—	—

1. Expenses include $4,591 of preferred return payable to Innergex on the $43,720 preferred units. Excluding these elements, the Net earnings would have been $2,487.

(in thousands of Canadian dollars, except as noted and amounts per share)

Innergex Europe (2015) Limited Partnership and its subsidiaries

The Corporation owned 100% of the participating units of Innergex Europe (2015) Limited Partnership, formed for the acquisition of seven operating wind farms in France on April 15, 2016.

On June 10, 2016, RRMD subscribed an amount of $38,357 in exchange of 30.45% of the common units and a debenture of $31,965 issued by Innergex Europe (2015) Limited Partnership. An additional investment of $9,397 including a debenture of $6,224 was made by RRMD upon the closing of the acquisition of the two wind farms on December 22, 2016.

An investment of $8,568 including a debenture of $6,478 was made by RRMD into Innergex Europe (2015) Limited Partnership to partly finance a portion of the acquisition of Yonne on February 21, 2017.

An investment of $31,119 including a debenture of $22,296 was made by RRMD into Innergex Europe (2015) Limited Partnership to partly finance a portion of the acquisition of Rougemont 1-2 and Vaite on May 24, 2017.

An investment of $16,923 including a debenture of $10,994 was made by RRMD into Innergex Europe (2015) Limited Partnership to partly finance a portion of the acquisition of Plan Fleury and Les Renardières on August 25, 2017.

As at	December 31, 2017	December 31, 2016
Summary Statement of Financial Position		
Current assets	76,091	19,036
Non-current assets	967,260	325,310
	1,043,351	344,346
Current liabilities	119,935	32,475
Non-current liabilities	934,396	316,508
Deficit attributable to owners	(21,541)	(5,416)
Non-controlling interest	10,561	779
	1,043,351	344,346

(in thousands of Canadian dollars, except as noted and amounts per share)

	Year ended December 31, 2017	Period of 261 days ended December 31, 2016
Summary Statement of Earnings and Comprehensive loss		
Revenues	52,300	9,836
Expenses [1]	75,838	21,145
Net loss	(23,538)	(11,309)
Other comprehensive income (loss)	354	(799)
Total comprehensive loss	(23,184)	(12,108)
Net loss attributable to:		
Owners of the parent	(16,370)	(8,601)
Non-controlling interests	(7,168)	(2,708)
	(23,538)	(11,309)
Total comprehensive loss attributable to:		
Owners of the parent	(16,124)	(9,157)
Non-controlling interests	(7,060)	(2,951)
	(23,184)	(12,108)
Summary Statement of Cash Flows		
Net cash inflow from operating activities	7,171	(17,443)
Net cash inflow from financing activities	177,775	121,132
Net cash outflow from investing activities	(182,484)	(100,504)
Net increase in cash and cash equivalents	2,462	3,185
Distributions paid to non-controlling interests	640	640

1. Expenses include $1,883 ($1,679 in 2016) of acquisition costs, $4,999 ($1,470 in 2016) of interest payable to RRMD on the $77,957 ($38,189 in 2016) debenture, $11,496 ($4,265 in 2016) of preferred return payable to Innergex on the $178,059 ($87,227 in 2016) preferred units and $51 ($603 in 2016) of interest payable to Innergex on a temporary bridge loan. Excluding these elements, the Net loss would have been $5,109 ($3,292 in 2016). Expenses also include non-cash expenses such as depreciation and amortization of a total amount of $31,679 ($9,805 in 2016).

28.1 Financial support to structured entities

Kwoiek Creek Resources L.P

Based on the contractual arrangements between the Corporation and the other partner, the Corporation concluded that it has control over Kwoiek Creek Resources L.P.

The Corporation invested $39,752 in preferred units of Kwoiek Creek Resources L.P. This investment provides the Corporation with preferred distributions.

Kwoiek Creek Resources Inc., the other partner, invested $3,662 in subordinated debt of Kwoiek Creek Resources L.P.

Interests or distributions on the aggregate subordinated debt and preferred units will be payable annually subject to the availability of gross revenues. The interests or distributions on preferred units are payable before making any distributions on the common units.

Mesgi'g Ugju's'n (MU) Wind Farm L.P

Based on the contractual arrangements between the Corporation and the other partner, the Corporation concluded that it has control over Mesgi'g Ugju's'n (MU) Wind Farm L.P.

The Corporation is responsible for financing equity required by the project. Mi'gmawei Mawiomi Resources L.P., the other partner, can participate in the financing of the equity for an amount up to a maximum of $2,300.

(in thousands of Canadian dollars, except as noted and amounts per share)

The Corporation invested a total of $63,315 in units of Mesgi'g Ugju's'n (MU) Wind Farm L.P. This investment provides the Corporation with distributions. The Mi'gmaq partner invested a total of $2,300 in units of the Mesgi'g Ugju's'n (MU) Wind farm L.P.

29. JOINT OPERATIONS

Name of entities	Principal activity	Place of creation and operation	Proportion of ownership interest and voting rights held by the Corporation	
			December 31, 2017	December 31, 2016
Innergex AAV, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex BDS, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex CAR, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex GM, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex MS, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Others	operate wind farm facilities	Quebec	50%	50%

(1). The Corporation owns through the Limited Partnerships a 38%ownership interest in the assets, liabilities, revenues and expenses and 50% voting rights of the joint operations.

30. RELATED PARTY TRANSACTIONS

Related party transactions conducted in the normal course of operations are measured at fair value which is the amount established and agreed to by the related parties, unless specific requirements within IFRS require different treatment.

The Corporation's subsidiaries have entered into the following transactions with partners:

Sainte Marguerite L.P.'s debenture to RRMD (see note 22 j)
Magpie's convertible debenture to the municipality (see note 22 p)
Innergex Europe (2015) Limited Partnership's debenture to RRMD (see note 22 cc)
The Corporation's partner made a loan to Kwoiek Creek Resources L.P. (see note 22 ee)

31. FINANCIAL INSTRUMENTS

a. Fair value disclosures

Fair value estimates are made at specific points in time using available information about the financial instrument in question. These estimates are subjective in nature and often cannot be determined precisely.

As at December 31, 2017, the Corporation determined that the carrying values of its current financial assets and liabilities approximated their fair values due to these instruments' short term maturity.

As at December 31, 2017, the Corporation determined that the carrying values of its short-term investments and government-backed securities included in reserve accounts approximated their fair values due to these instruments' short-term maturity.

(in thousands of Canadian dollars, except as noted and amounts per share)

The fair value of each debt instrument is estimated utilizing standard financial industry practices where future expected cash flows are discounted at discount rates based on the interest rate and credit conditions prevailing in the financial markets as of the valuation date. Notably, for fixed rate instruments, contractual cash flows are discounted at an appropriate yield to maturity. For floating rate instruments, future expected contractual interest rates represent the sum of future expected levels of the reference interest rate index and the instrument’s quoted margin whereas discount rates represent the sum of future expected levels of the reference index and an appropriate discount margin. Appropriate yields to maturity and discount margins are estimated utilizing the available quoted or indicative pricing of individual debt instruments or indices whose credit is deemed comparable to the debt instruments being evaluated.

The carrying values of the floating rate long-term debts are approximately $127,986 lower than their estimated fair values based on the swap interest curve on December 31, 2017. The carrying values of the fixed-rate debts, the bonds and the debentures are approximately $138,612 lower than their estimated fair market values based on the swap interest curve on December 31, 2017. All of these are estimated using Level 2 valuation techniques.

Financial assets or liabilities measured at fair value are derivative financial instruments which are level 3 for PPAs inflation provision and level 2 for interest rate swap, bond forward contracts and foreign exchange forwards contracts.

b. Interest rate risk

The Corporation entered into fixed rate debts or hedge agreements to mitigate the risk of fluctuations in the interest rates on its non-recourse long-term debt. It also use hedge agreements on a portion of its revolving credit facilities.

The interest hedging instruments and related risks are described in detail in Note 10.

c. Credit risk

Credit risk relates to the possibility that a loss may occur from a party's failure to comply with contractual requirements.

Cash and cash equivalents are mainly held at large Canadian financial institutions and, to a lesser degree, at major U.S. and European financial institutions.

The financial derivatives and related risks are described in detail in Note 10.

The accounts receivable and related risks are described in detail in Note 16.

The reserve accounts and related risks are described in detail in Note 17.

d. Liquidity risk

Liquidity risk relates to the capacity of the Corporation to meet liabilities as they become due. Certain covenants of long-term borrowing contracts could prevent the Corporation from repatriating funds from certain subsidiaries.

Some hedging instruments have embedded early termination options. The triggering of these options could pose a liquidity risk. Should the early termination option be triggered, a presumed realized loss would be offset by the savings realized on future expenses, as a negative value would be the result of an environment in which actual rates are more beneficial than the rates embedded in the swap.

The Corporation has a negative working capital of $25,234 as at December 31, 2017 (positive working capital of $31,859 in 2016). If necessary, the Corporation can use its revolving credit facilities, as described in Note 22 a), of which $149,904 was available as at December 31, 2017 ($185,313 in 2016). In addition, in the event of lower revenue due to a decline in production or to a major equipment breakdown, the Corporation has available reserve accounts (as described in Note 17) and is covered by insurance plans. Accordingly, the Corporation believes its current working capital to be sufficient to meet all of its needs.

The following table presents the maturities of the financial liabilities:

	Less than 3 months	Between 3 months and 1 year	Between 1 year and 5 years
Dividends payable to shareholders	19,406		
Accounts payable and other payables	68,591	22,441	
Income tax payable	241	3,041	
Current portion of derivative financial instruments	3,024	19,725	
Current portion of long-term debt	44,142	65,733	
Current portion of other liabilities	249	251	
Derivative financial instruments			40,982
Long-term debt			676,398
Other liabilities			5,541
Liability portion of convertible debentures			96,246
Total	135,653	111,191	819,167

The maturities are determined based on the expected terms of the payments.

e. Market risk

Market risk is related to fluctuations in the fair value or future cash flows of a financial instrument because of market price variations. Market risk includes foreign exchange and interest rate risks, described under separate headings, and other price risks.

The sale of electricity is made pursuant to long-term agreements where the offtakers are committed to take and pay for the total production, up to certain annual limits. The inflation clauses of the sale price of electricity are normally allowing the Corporation to cover its increase of variable operation expenses. The inflation clauses included in some of the electricity purchasing contracts with Hydro-Québec are limited to a maximum of 6% per year.

f. Foreign exchange risk

The foreign exchange risk relates to fluctuations in the U.S. dollar and Euro against the Canadian dollar.

The Corporation has subsidiaries in Europe for which the revenues, net of the expenses incurred, are repatriated to Canada. The Corporation's foreign exchange forwards are denominated in Euro dollars. Repatriated funds that are not used to service the Euro dollar-denominated foreign exchange forwards are converted into Canadian dollars at the exchange rate in effect on the conversion date. The Corporation's net risk is estimated to be $167 for each 1% increase in the value of the Canadian dollar against the Euro dollar. The Corporation uses a portion of its Euro dollar-denominated foreign exchange forwards to hedge its investment in its subsidiaries, as described in Note 10.

The Corporation has subsidiaries in the United States for which the revenues, net of the expenses incurred, are repatriated to Canada. A portion of the Corporation's debts is denominated in U.S. dollars. Repatriated funds that are not used to service the U.S. dollar-denominated debt are converted into Canadian dollars at the exchange rate in effect on the conversion date. The Corporation's net risk is estimated to be $1 for each 1% increase in the value of the Canadian dollar against the U.S. dollar. The Corporation uses a portion of its U.S. dollar-denominated debt to hedge its investment in its subsidiaries, as described in Note 10.

(in thousands of Canadian dollars, except as noted and amounts per share)

32. COMMITMENTS AND CONTINGENCIES

In addition to the commitments of the Joint Venture presented in note 9, the Corporation entered into the following transactions:

a. Power Purchase Agreements

Quebec facilities

Under PPAs with terms varying from 20 to 25 years and expiring between 2018 and 2036, Hydro-Québec agreed to purchase all of the electrical energy produced by the facilities and wind farms located in the Province of Quebec. Certain facilities have an agreed maximum quantity of electricity and a minimum quantity of electricity to deliver during each of the consecutive 12-month periods.

Total revenues from Hydro-Québec amounted to $154,360 in 2017 ($102,935 in 2016), representing 39% of the Corporation's revenues (35% in 2016). The Corporation is economically dependent on Hydro-Québec given the size of its revenues.

British Columbia facilities

Under PPAs with terms varying from 20 to 40 years and expiring between 2018 and 2057, British Columbia Hydro and Power Authority agreed to purchase all of the electrical energy produced by the facilities located in the Province of British-Columbia.

Total revenues from British Columbia Hydro and Power Authority amounted to $155,807 in 2017 ($139,012 in 2016) representing 39% of the Corporation's revenues (47% in 2016). The Corporation is economically dependent on British Columbia Hydro and Power Authority given the size of its revenues.

Ontario facilities

Under PPAs with terms varying from 20 to 30 years and expiring between 2025 and 2032, Hydro One inc. and its affiliates agreed to purchase all of the electrical energy produced by the facilities located in Ontario.

Total revenues from the Ontario facilities amounted to $22,553 ($21,250 in 2016) representing 6% of the Corporation's revenues (7% in 2016).

Europe facilities

Under PPAs with terms of 15 years expiring between 2024 and 2032, Électricité de France and S.I.C.A.E Oise agreed to purchase all of the electrical energy produced by the facilities located in France.

Total revenues from Électricité de France and S.I.C.A.E Oise amounted to $52,300 in 2017 ($9,836 in 2016) representing 13% of the Corporation's revenues (3% in 2016).

Idaho facility

Under a PPAs with a 35-year term and expiring in 2030, Idaho Power Company agreed to purchase all of the electricity produced by Horseshoe Bend Hydroelectric Corporation.

Total revenues from Idaho Power Company amounted to $3,523 in 2017 ($4,226 in 2016), representing 1% of the Corporation's revenues (1% in 2016).

b. Other Commitments

(i) Hydroelectric facilities

The Corporation and its subsidiaries entered into royalties and other commitments related to surrounding municipalities, land owners and the operation of the hydroelectric facilities.

Ashlu Creek facility

The ownership of the assets of the project will be transferred to a First Nation in 2049 for a nominal financial consideration.

Boulder Creek facility

40% of the Corporation's ownership of the project will be transferred to the First Nation partner in 2057 for no financial consideration.

Big Silver facility

A 50% ownership of the assets of the project will be transferred to one of the First Nations partners in 2056 for no financial consideration.

Glen Miller facility

Glen Miller Power, Limited Partnership entered into a 30-year lease agreement, ending in December 2035, for the site that is in commercial operation. The lease has a 15-year extension option upon terms and conditions to be negotiated.

Glen Miller Power, Limited Partnership is committed to remit the facility to the lessor of the site, at the end of the lease agreement, for no consideration.

Harrison Hydro L.P.

The ownership of Douglas Creek Project L.P. and Tipella Creek Project L.P. will be transferred to a First Nation in 2069 for no financial consideration.

Kwoiek Creek facility

The Corporation's ownership of the project will be transferred to the First Nation partner in 2054 for no financial consideration. Subsequently, the Corporation will receive a royalty based on a percentage of the gross revenues less operation costs.

Rutherford Creek facility

Rutherford L.P. agreed to make payments to the former owners, following the expiry of the Rutherford Creek PPA in 2024. This payment is based on the difference between the then selling price of electricity and the last selling price of electricity under the agreement, adjusted annually following the expiry of the agreement by 50% of the increase or decrease in the CPI over the previous 12 months. This amount will correspond to 35% of the gross revenues attributable to the difference for the 20-year period following the expiry of the power purchase agreement. After the 20-year period, that portion of the payment will correspond to 30% of the gross revenues attributable to the difference. This commitment is secured by the Rutherford L.P. facility but is subordinated to the term loan described in Note 22 g).

Tretheway facility

50% of the Corporation's ownership will be transferred to a First Nation in 2055 for no financial consideration.

Upper Lillooet facility

40% of the Corporation's ownership of the project will be transferred to the First Nation partner in 2057 for no financial consideration.

(ii) Wind farm facilities

The Corporation and its subsidiaries entered into royalties and other commitments related to amounts to set aside for the dismantling of wind farm components, commitments to surrounding municipalities and land owners and the operation of the wind farms.

Europe

The French subsidiaries entered into commitments related to land leases, maintenance and management contracts for the operations of the wind farms.

(iii) Stardale Solar LP

Stardale Solar LP entered into a contract for the operations and maintenance of the solar farm.

(iv) Operating leases

The Corporation is engaged under long-term operating leases of premises which will expire between 2018 and 2028.

c. Summary of commitments

As at December 31, 2017, the expected schedule of commitment payments is as follows:

Year of expected payment	Hydroelectric Generation	Wind Power Generation	Solar Generation	Site Development	Total
2018	1,169	14,759	219	1,535	17,682
2019	1,032	17,622	225	1,360	20,239
2020	1,066	17,862	231	1,317	20,476
2021	965	18,196	236	1,254	20,651
2022	953	19,462	242	1,249	21,906
Thereafter	21,405	192,680	—	6,443	220,528
Total	26,590	280,581	1,153	13,158	321,482

d. Contingencies

The Corporation is subject to various claims that arise in the normal course of business. Management believes that adequate provisions have been made in the accounts where required. Although it is not possible to estimate the extent of potential costs and losses, if any, management believes that the ultimate resolution of such contingencies will not have an adverse effect on the financial position of the Corporation.

33. CAPITAL DISCLOSURES

The Corporation's strategy in managing its capital is: (i) to develop or acquire high-quality power production facilities that generate sustainable and stable cash flows, with the objective of achieving a high return on invested capital, and (ii) to distribute a stable dividend.

The Corporation seeks to achieve its objectives by:

- Maintaining the generating capacity and enhancing the operation of its hydroelectric facilities, wind farms and solar farm; and
- Acquiring and developing new electricity-generating facilities.

The Corporation maintains its generating capacity by investing the necessary funds to maintain and continually upgrade its equipment. The Corporation also invests amounts on an annual basis in major maintenance reserve in order to fund any major maintenance of hydroelectric facilities, wind farms or solar farm which may be required to preserve the Corporation's generating capacity.

The Corporation determines the amount of capital required, and its allocation between debt and equity, for the acquisition and development of new electricity-generating facilities by considering the specific characteristics of stability and growth of each facility. This determination is made in order to distribute a stable dividend while maintaining an acceptable level of indebtedness.

(in thousands of Canadian dollars, except as noted and amounts per share)

The Corporation has a hydrology/wind power reserve. This reserve could be used in the event that the net available cash for any given year is less than expected, due to normal changes in hydrology or wind conditions or other unpredictable factors.

The Corporation's capital is composed of long-term debt, convertible debentures and shareholders' equity. Total capital amounts to $3,703,893 at year-end.

The Corporation uses equity primarily to finance the development of projects. The Corporation uses long-term debt to finance the construction of its facilities. The Corporation expects to finance 70% to 85% of its construction costs mostly through non-recourse long-term debt financing.

Future development and construction of new facilities, development of projects, expenses on prospective projects and other capital expenditures will be financed out of cash generated from the Corporation's operating facilities, borrowings and/or issuance of additional equity. To the extent that external sources of capital, including issuance of additional securities of the Corporation, become limited or unavailable, the Corporation's ability to make necessary capital investment to construct new or maintain existing project facilities will be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion.

Under the terms of the Revolving credit facilities described in Note 22 a), the Corporation needs to maintain, a leverage ratio and an interest coverage ratio. If the ratios are not met, the lender has the ability to recall the facility.

Regarding the respective non-recourse projects financing, some subsidiaries of the Corporation need to maintain minimum debt coverage ratios. If the ratios of a particular project financing are not met, the lenders could have the ability to recall the particular debt. Certain financial restrictive clauses could prevent the subsidiaries from making distributions to the Corporation.

All debt covenants are monitored on a regular basis by the Corporation. During the year, the Corporation and its subsidiaries met all the financial and non-financial conditions related to their credit agreements.

The Corporation's capital management objectives, policies and procedures are to ensure the stability and sustainability of the dividend payable to its shareholders and the development or acquisition of power production facilities. The objectives were identical in prior years.

34. SEGMENT INFORMATION

Geographic segments

The Corporation had interests in 30 hydroelectric facilities, seven wind farms and one solar farm in Canada, 15 wind farms in France and one hydroelectric facility in the United States. The Corporation operates in three principal geographical areas, which are detailed below:

	Year ended December 31	
	2017	2016
Revenues		
Canada	344,440	278,723
Europe	52,300	9,836
United States	3,523	4,226
	400,263	292,785

As at	December 31, 2017	December 31, 2016
Non-current assets, excluding derivatives financial instruments and deferred tax assets		
Canada	2,977,859	3,005,720
Europe	973,740	318,924
United States	7,052	7,365
	3,958,651	3,332,009

Major Customers

A major customer is defined as an external customer whose transaction with the Corporation amount to 10% or more of the Corporation's annual revenues. The Corporation has identified three major customers. The sales of the Corporation to these major customers are the following:

Major customer	Segment	Year ended December 31	
		2017	2016
British Columbia Hydro and Power authority	Hydroelectric generation	155,807	139,012
Hydro-Québec	Hydroelectric and wind power generation	154,360	102,935
Électricité de France	Wind power generation	49,987	8,647
		360,154	250,594

Operating segments

The Corporation has four operating segments: (a) hydroelectric generation (b) wind power generation (c) solar power generation and (d) site development.

Through its hydroelectric, wind power and solar power generation segments, the Corporation sells electricity produced by its hydroelectric, wind farm and solar facilities to publicly owned utilities or other creditworthy counterparties. Through its site development segment, it analyzes potential sites and develops hydroelectric, wind and solar facilities up to the commissioning stage.

The accounting policies for these segments are the same as those described in the significant accounting policies. The Corporation evaluates performance based on earnings (loss) before finance costs, income taxes, depreciation, amortization, impairment of project development costs, other net (revenues) expenses , share of (earnings) loss of joint ventures and unrealized net (gain) loss on financial instruments. The Corporation accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind power generation or solar power generation segments are accounted for at cost.

(in thousands of Canadian dollars, except as noted and amounts per share)

The operations of the Corporation's operating segments are conducted by different teams, as each segment has different skill requirements.

For the year ended December 31, 2017					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	226,211	155,307	16,824	1,921	400,263
Expenses:					
Operating	44,151	26,098	678	745	71,672
General and administrative	9,934	7,271	144	457	17,806
Prospective projects	—	—	—	12,057	12,057
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on financial instruments	172,126	121,938	16,002	(11,338)	298,728
Finance costs					146,766
Other net expenses					2,453
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					149,509
Depreciation					92,762
Amortization					36,667
Share of earnings of joint ventures					(4,638)
Unrealized net gain on financial instruments					(2,245)
Earnings before income taxes					26,963

As at December 31, 2017					
Goodwill	8,269	30,311	—	—	38,580
Total assets	2,425,646	1,651,537	101,449	11,824	4,190,456
Total liabilities	2,093,158	1,516,245	105,061	25,803	3,740,267
Acquisition of property, plant and equipment during the period	18,804	352,968	12	185,884	557,668

(in thousands of Canadian dollars, except as noted and amounts per share)

For the year ended December 31, 2016					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	211,881	63,238	17,666	—	292,785
Expenses:					
Operating	37,197	13,515	757	—	51,469
General and administrative	8,459	4,090	152	2,344	15,045
Prospective projects	—	—	—	10,288	10,288
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on financial instruments	166,225	45,633	16,757	(12,632)	215,983
Finance costs					95,254
Other net expenses					265
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					120,464
Depreciation					61,722
Amortization					28,581
Share of earnings of joint ventures					(2,526)
Unrealized net gain on financial instruments					(4,292)
Earnings before income taxes					36,979

As at December 31, 2016					
Goodwill	8,269	—	—	—	8,269
Total assets	1,993,033	1,003,964	108,231	498,976	3,604,204
Total liabilities	1,537,791	847,148	113,538	620,495	3,118,972
Acquisition of property, plant and equipment during the year	3,420	219,813	11	369,723	592,967

(in thousands of Canadian dollars, except as noted and amounts per share)

35. SUBSEQUENT EVENTS

a. Dividends declared by the Board of Directors

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
02/21/2018	03/30/2018	04/16/2018	0.1700	0.2255	0.359375

b. Arrangement Agreement to acquire Alterra Power Corp.

Acquisition of Alterra Power Corp.

On February 6, 2018, Innergex announced the completion of the acquisition of Alterra by way of an arrangement agreement pursuant to which Innergex acquired all of the issued and outstanding common shares of Alterra.

The Innergex common shares issuable to Alterra shareholders with the transaction represent an ownership of approximately 18% of the combined corporation. One member of the current Board of Directors of Alterra joined the Board of Directors of Innergex at the closing of the Transaction.

The total purchase for Alterra is $450,865 comprised of a cash consideration of $120,258 and the issuance of 24,327,225 common shares of the Corporation at a price of $13.59 for a value of $330,607.

The purchase price allocation has not been prepared as of today as the information is not available yet.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. Alterra added an additional gross installed capacity of 2,896 MW to the Corporation's portfolio.

Support from la Caisse de dépôt et placement du Québec

Concurrently to the closing of the acquisition of Alterra, Innergex has closed a $150 million subordinated unsecured 5-year term loan at a 5.13% interest rate with la Caisse de dépôt et placement du Québec.

c. Increase to the revolving credit facilities

On February 6, 2018 the Corporation announced that it had increased its revolving credit facilities by $225 million to $700 million and added a new lender to the syndicate of lenders. The maturity of the revolving credit facilities remains December 2022.

d. Decision rendered on water rights

On January 14, 2014, Harrison Hydro Project Inc., Fire Creek Project Limited Partnership, Lamont Creek Project Limited Partnership, Stokke Creek Project Limited Partnership, Tipella Creek Project Limited Partnership and Upper Stave Project Limited Partnership (the "Appellants") filed appeals with the Environmental Appeal Board challenging a determination by the Comptroller of the Water Rights respecting the water rental rates to be charged under the Water Act R.S.B.C. 1996, c. 483 in respect of the Fire Creek Facility, Lamont Creek Facility, Stokke Creek Facility, Tipella Creek Facility and Upper Stave River Facility. On December 8, 2015, the Environmental Appeal Board Decision issued its decision rejecting the appeal. On January 20, 2016, an application for judicial review was filed to the British Columbia Supreme Court ("BCSC"). On February 27, 2017, the BCSC declined to set aside the Environmental Appeal Board Decision. On March 21, 2017, the Appellants filed an appeal of the BCSC decision and on February 8, 2018, in a split decision, the British Columbia Court of Appeal refused to set aside the BCSC decision. The Appellants are currently analysing the possibility of filing a petition for permission to appeal to the Supreme Court of Canada. The outcome of the judicial review could affect the expenses of these entities on an annual basis going forward which would represent an approximately $1,600 aggregate increase for water rights. The amount for such potential increase water rights rentals was included in the years 2013, 2014, 2015 and 2016 results of the Corporation, which owns a 50.0024% indirect interest in those facilities.

(in thousands of Canadian dollars, except as noted and amounts per share)

SHAREHOLDER INFORMATION

Head Office

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Stock Exchange Listing

Innergex Renewable Energy Inc.'s securities are listed on the Toronto Stock Exchange (TSX).

The Corporation is included in the following S&P/TSX indices:

- Composite Index
- Composite Dividend Index
- Composite High Dividend Index
- Completion Index
- Renewable energy and Clean Technology Index

Common Shares - TSX: INE

Innergex Renewable Energy Inc. had 108,608,083 common shares outstanding as at December 31, 2017, with a closing price of $14.40 per share.

Series A Preferred Shares - TSX: INE.PR.A

Innergex Renewable Energy Inc. currently has 3,400,000 Series A preferred shares outstanding, with a nominal value of $25 and a fixed cumulative preferential annual cash dividend of $0.902 per share, payable quarterly on the 15th day of January, April, July and October. Series A preferred shares are not redeemable by the Corporation prior to January 15, 2021.

Series C Preferred Shares - TSX: INE.PR.C

Innergex Renewable Energy Inc. currently has 2,000,000 Series C preferred shares outstanding, with a nominal value of $25 and a fixed-rate cumulative preferential annual cash dividend of $1.4375 per share, payable quarterly on the 15th day of January, April, July and October. Series C preferred shares are redeemable by the Corporation since January 15, 2018.

Convertible Debentures - TSX: INE.DB.A

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for an aggregate principal amount of $100.0 million, bearing interest at a rate of 4.25% per annum, payable semi-annually on February 28 and August 31 of each year, commencing on February 28, 2016. The debentures will be convertible at the holder's option into Innergex common shares at a conversion price of $15.00 per share, representing a conversion rate of 66.6667 common shares per each thousand of dollars of principal amount of debentures. The debentures will mature on August 31, 2020 and will not be redeemable before August 31, 2018, except in certain limited circumstances. The convertible debentures are subordinated to all other indebtedness of the Corporation.

Credit Rating by Standard & Poor's

Innergex Renewable Energy Inc.	BBB-
Series A Preferred Shares	P-3
Series C Preferred Shares	P-3

Dividend

On February 21, 2018, the Board of Directors announced an increase of $0.02 in the annual dividend that the Corporation intends to distribute to its shareholders of common shares. This increase, raising the annual dividend from $0.66 to $0.68, payable quarterly, reflects the execution of the Corporation's strategy for building shareholder value. This is the fifth consecutive $0.02 annual dividend increase.

Dividend Reinvestment Plan (DRIP)

Innergex Renewable Energy Inc. offers a Dividend Reinvestment Plan (DRIP) for its shareholders of common shares. This plan enables eligible holders of common shares to acquire additional common shares of the Corporation by reinvesting all or part of their cash dividends. For more information about the Corporation's DRIP, please visit our website at innergex.com or contact the DRIP administrator: Computershare Trust Corporation of Canada. Please note that if you wish to enrol in the DRIP but own your shares indirectly through a broker or financial institution, you must contact this intermediary and ask them to enrol in the DRIP on your behalf.

Transfer Agent and Registrar

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents, please contact:	***Computershare Investor Service Inc.*** 1500 Robert-Bourassa, Suite 700 Montreal QC H3A 3S8 Tel. 1 800 564.6253 514 982.7555 service@computershare.com

Independent Auditor

Deloitte LLP

Ce document est disponible en français.
Pour la version numérique, visitez innergex.com
Pour la version papier, écrivez-nous à info@innergex.com

INNERGEX

Renewable Energy.
Sustainable Development.