FOR THE
PERIOD ENDED
JUNE 30, 2017

These condensed consolidated financial statements have neither been audited nor reviewed by the Corporation's independent auditors.

Innergex Renewable Energy Inc. is a leading Canadian independent renewable power producer. Active since 1990, the Corporation develops, owns, and operates run-of-river hydroelectric facilities, wind farms and solar photovoltaic farms and carries out its operations in Quebec, Ontario and British Columbia in Canada, in France and in Idaho, USA. The Corporation's shares are listed on the Toronto Stock Exchange ("TSX") under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures 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.

INTRODUCTION

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 six-month period ended June 30, 2017, and reflects all material events up to August 3, 2017, 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 unaudited condensed consolidated financial statements and the accompanying notes for the three- and six-month periods ended June 30, 2017, and with the Corporation's Financial Review at December 31, 2016.

The unaudited condensed consolidated financial statements attached to this MD&A and the accompanying notes for the three- and six-month periods ended June 30, 2017, along with the 2016 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Some amounts included in this MD&A have been rounded to make reading easier, which may affect some calculations.

SECOND QUARTER ("Q2") AND SIX-MONTH PERIOD ENDED JUNE 30, 2017 HIGHLIGHTS

- Production was 92% of the long-term average ("LTA") for Q2 and 91% of the LTA for the six-month period.
- Revenues increased 25% to $109.5 million in Q2 and 22% to $184.1 million for the six-month period ended June 30, 2017, compared with the corresponding periods last year.
- Adjusted EBITDA rose 29% to $85.9 million in Q2 and 19% to $136.9 million for the six-month period ended June 30, 2017, compared with the corresponding periods last year.
- Innergex completed the acquisition of three wind projects (Rougemont 1-2 and Vaite) with a total aggregate capacity of 119.5 MW in France's Bourgogne-Franche-Comté region. Rougemont-2 is still in construction.
- In British Columbia, the 25.3 MW Boulder Creek hydroelectric facility began commercial operation on May 16, 2017.

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

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 accumulated and communicated by others to the President and Chief Executive Officer and the Chief Financial Officer in a timely manner, particularly during the period in which the interim and 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 applicable 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 applicable to the Corporation.

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 certified that: (a) there were no material weaknesses relating to the DC&P and ICFR for the three-month period ended June 30, 2017; (b) they have limited the scope of the Corporation's design of DC&P and ICFR to exclude the control policies and procedures of Montjean Energies, Theil Rabier Energies, Eoles Yonne S.A.S., Energies du Plateau Central S.A.S, Energies du Plateau Central 2 S.A.S and Energie du Rechet S.A.S; and (c) there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR during the three-month period ended June 30, 2017. The design and evaluation of the operating effectiveness of the DC&P and ICFR for the Montjean Energies, Theil Rabier Energies, Eoles Yonne S.A.S., Energies du Plateau Central S.A.S, Energies du Plateau Central 2 S.A.S and Energie du Rechet S.A.S will be completed in the 12 months following the dates of acquisition. A summary of the financial information about Montjean Energies, Theil Rabier Energies, Eoles Yonne S.A.S., Energies du Plateau Central S.A.S, Energies du Plateau Central 2 S.A.S and Energie du Rechet S.A.S is presented in the Non-wholly Owned Subsidiaries section of this MD&A.

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”). 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 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 dividend increases 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 and solar irradiation, performance of operating facilities, financial market conditions and the Corporation’s success in developing new facilities.

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 Corporation’s *Annual Information Form* in the “Risk Factors” section 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 capital markets; liquidity risks related to derivative financial instruments ("Derivatives"); variability in hydrology, 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 to renew any power purchase agreement on equivalent terms and conditions; 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;

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; the exposure to many different forms of taxation in various jurisdictions; changes in general economic conditions; regulatory and political risks; the ability to secure appropriate land; reliance on power purchase agreements; 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 and sun resources and associated electricity production; dam failure; natural disasters and *force majeure*; cybersecurity; sufficiency of insurance coverage limits and exclusions; a credit rating that may not reflect the Corporation's actual performance or a lowering (downgrade) of the credit rating; potential undisclosed liabilities associated with acquisitions; 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.

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.

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; and for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation. 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 Umbata Falls and Viger-Denonville, which are accounted for using the equity method).	Improper assessment of water, wind and sun resources and associated electricity production Variability in hydrology, wind regimes and solar irradiation Equipment failure or unexpected operations and maintenance activity Natural disaster
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 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

Principal Assumptions	Principal Risks and Uncertainties
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 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
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

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 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.

References in this document to "Adjusted EBITDA Margin" are to Adjusted EBITDA divided by revenues.

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.

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.

References to “Payout Ratio” are to dividends declared on common shares divided by Free Cash Flow.

Readers are cautioned that Adjusted EBITDA and Adjusted Net Earnings should not be construed as an alternative to net earnings and Free Cash Flow should not be construed as an alternative to cash flows from operating activities, as determined in accordance with IFRS.

ADDITIONAL INFORMATION AND UPDATES

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.

OVERVIEW

The Corporation is a developer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind power and solar photovoltaic (“PV”) 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:

- 51 facilities in commercial operation (the “Operating Facilities”). Commissioned between 1992 and May 2017, the facilities have a weighted average age of approximately 7.3 years. They sell the generated power under long-term Power Purchase Agreements (“PPA”) that have a weighted average remaining life of 20.1 years (based on gross long-term average production);

- One project scheduled to begin commercial operations in the fourth quarter of 2017 (the “Development Project”);

- Numerous projects that have secured land rights, for which an investigative permit application has been filed or for which a proposal has either 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.

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

INNERGEX

	Operating Facilities	Development Projects	Prospective Projects
Hydro			
Gross capacity:	731.5 MW	-	990.0 MW
Net capacity[1]:	558.8 MW	-	840.0 MW
Wind			
Gross capacity:	993.2 MW	44.5 MW	2,800.0 MW
Net capacity[1]:	470.7 MW	30.9 MW	2,570.0 MW
Solar			
Gross capacity:	33.2 MW	-	150.0 MW
Net capacity[1]:	33.2 MW	-	150.0 MW
Total			
Gross capacity:	1757.9 MW	44.5 MW	3,940.0 MW
Net capacity[1]:	1062.7 MW	30.9 MW	3,560.0 MW

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.

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 stable dividend.

Dividend Policy

The Corporation currently distributes an annual dividend of $0.66 per common share, payable quarterly.

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 tests imposed under corporate law for the declaration of dividends and other relevant factors.

Use Key Performance Indicators

The Corporation measures its performance using key performance indicators that include or could include comparing power generated in megawatt-hours ("MWh") and gigawatt-hours ("GWh") with a long-term average, Adjusted EBITDA and Adjusted EBITDA Margin, Free Cash Flow, Adjusted Net Earnings and Payout Ratio. These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. 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. Please refer to the "Non-IFRS Measures" section for more information.

Maintain Diversification of Energy Sources

The amount of electricity generated by the Operating Facilities is generally dependent on the availability of water flows, wind regimes and solar irradiation. Lower-than-expected water flows, wind regimes or solar irradiation in any given year could have an impact on the Corporation's revenues and hence on its profitability. Innergex owns interests in 31 hydroelectric facilities, which draw on 27 watersheds, 19 wind farms and 1 solar farm, providing significant diversification in terms of operating revenue sources. Furthermore, the nature of hydroelectric, wind and solar 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	369.7	12%	1,065.7	35%	1,002.7	33%	581.2	19%	3,019.4
WIND	564.9	30%	402.6	22%	356.4	19%	537.1	29%	1,861.0
SOLAR	7.2	19%	12.4	33%	12.5	33%	5.7	15%	37.9
Total	941.9	19%	1,480.7	30%	1,371.6	28%	1,124.0	23%	4,918.2

1. The consolidated long-term average production is the annualized LTA for the facilities in operation at August 3, 2017. 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.

SECOND QUARTER UPDATE

Summary of Operating and Financial Performance

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
PRODUCTION				
Power generated (MWh)	1,322,781	1,176,451	2,045,053	1,840,838
LTA (MWh)	1,437,100	1,045,265	2,257,734	1,602,286
Production as percentage of LTA	92%	113%	91%	115%
STATEMENT OF EARNINGS				
Revenues	109,530	87,784	184,056	150,265
Adjusted EBITDA	85,920	66,863	136,861	114,542
Adjusted EBITDA Margin	78.4%	76.2%	74.4%	76.2%
Net earnings	14,100	15,677	11,766	22,873
DIVIDENDS				
Dividend declared per Class A Preferred Share	0.2255	0.2255	0.4510	0.4510
Dividend declared per Class C Preferred Share	0.359375	0.359375	0.71875	0.71875
Dividend declared per common share	0.165	0.160	0.330	0.320

For the three-month period ended June 30, 2017, production was 92% of the LTA, due mainly to lower production from post-commissioning activities at Upper Lillooet River, Boulder Creek and Mesgi'g Ugju's'n facilities during the quarter and below-average wind regimes in France, partly offset by above-average water flows in Quebec and Ontario. Production increased 12%, revenues increased 25% and Adjusted EBITDA increased 29% compared with the same period last year. These increases are attributable mainly to the contribution of the Mesgi'g Ugju's'n wind farm and Big Silver Creek hydro facility commissioned in 2016, the Upper Lillooet River and Boulder Creek hydro facilities commissioned in 2017 and the recently acquired Montjean, Theil-Rabier, Yonne, Rougemont 1-2 and Vaite wind facilities. The increases were partly offset by lower production at most of our British Columbia hydro facilities and Quebec wind facilities.

For the six-month period ended June 30, 2017, production was 91% of the LTA, due mainly to lower production from post-commissioning activities at the Upper Lillooet River, Boulder Creek and Mesgi'g Ugju's'n facilities during the period, below-average water flows in British Columbia and below-average wind regimes in Quebec and France, partly offset by above-average water flows in Quebec and Ontario. Production increased 11%, revenues increased 22% and Adjusted EBITDA increased 19% compared with the same period last year. These increases are attributable mainly to the contribution of the Mesgi'g Ugju's'n

wind farm, the Big Silver Creek, Upper Lillooet River and Boulder Creek hydro facilities and the wind facilities in France acquired in 2016 and 2017; they were partly offset by lower production at most of our British Columbia hydro facilities and Quebec wind facilities. The Adjusted EBITDA was also impacted by a $3.2 million aggregate payment for water rights, which were reassessed for the years 2011 and 2012 for Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River. This payment resulted from 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 its 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 rental rates. A 49.99% portion of the water rights payment is allocated to the non-controlling interests.

The $14.1 million in net earnings for the three-month period ended June 30, 2017, compared with $15.7 million in net earnings for the same period last year, is attributable mainly to this year's below-average production compared with last year's above-average production, which explains the decrease in net earnings as opposed to the increase in revenues. As a result, the increase in finance costs and depreciation and amortization related primarily to the greater number of operating facilities and the unrealized net loss on derivative financial instruments were only partly offset by the increase in Adjusted EBITDA, the decrease in income tax expenses and the higher share of earnings of joint ventures.

The $11.8 million in net earnings for the six-month period ended June 30, 2017, compared with $22.9 million in net earnings for the same period last year, is attributable mainly to this year's below-average production compared with last year's above-average production, which explains the decrease in net earnings as opposed to the increase in revenues. As a results, the increase in finance costs and in depreciation and amortization were only partly offset by the increase in Adjusted EBITDA, the decrease in income tax expenses and the higher share of earnings of joint ventures.

Adjusted Net Earnings

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", which is a non-IFRS measure of the Corporation.

Impact on net earnings of financial instruments	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Net earnings	14,100	15,677	11,766	22,873
Add (Subtract):				
Unrealized net loss (gain) on financial instruments	470	(2,145)	(4,605)	(3,432)
(Recovery) income tax expense related to above items	(498)	864	634	1,199
Share of unrealized net (gain) loss on financial instruments of joint ventures, net of related income tax	(372)	164	(406)	704
Adjusted Net Earnings	13,700	14,560	7,389	21,344

Excluding gains and losses on financial instruments and the related income taxes, net earnings for the three-month period ended June 30, 2017, would have been $13.7 million, compared with net earnings of $14.6 million in 2016. The decrease is attributable mainly to this year's below-average production compared with last year's above-average production, which explains the decrease in net earnings as opposed to the increase in revenues. As a result, the $14.5 million increase in finance costs, the $9.8 million increase in depreciation and amortization and the $4.8 million decrease in deferred income taxes were only partly offset by the $19.1 million increase in Adjusted EBITDA and $1.3 million increase in share of earnings of joint venture.

Excluding gains and losses on financial instruments and the related income taxes, net earnings for the six-month period ended June 30, 2017, would have been $7.4 million, compared with net earnings of $21.3 million in 2016. The decrease is attributable mainly to this year's below-average production compared with last year's above-average production, which explains the decrease in net earnings as opposed to the increase in revenues. As a result, the $24.3 million increase in finance costs, the $20.0 million increase in depreciation and amortization and the $7.0 million decrease in deferred income taxes were only partly offset by the $22.3 million increase in Adjusted EBITDA and $2.5 million increase in share of earnings of joint ventures.

Payout Ratio

	Trailing 12 months ended June 30	
	2017	2016
Free Cash Flow[1]	75,888	78,939
Payout Ratio[1]	93%	84%

1. 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.

For the trailing twelve-month period ended June 30, 2017, the dividends on common shares declared by the Corporation corresponded to 93% of Free Cash Flow, compared with 84% for the corresponding prior twelve-month period. This negative impact is due mainly to lower free cash flow and higher dividend payments as a result of a 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, 94,000 shares following the exercise of stock options and 377,582 shares under the Dividend Reinvestment Plan ("DRIP").

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 Desjardins Group Pension Plan owns the remaining 30.45%.

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

Non-recourse debts related to the projects, which were already in place, will amount to €174.3 million (or $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 once the three projects are in commercial operation, enough to power about 58,400 French households. All the electricity produced by these wind farms will be sold under fixed-price power purchase agreements (PPAs), with a portion of the price being adjusted according to inflation indexes, for an initial term of 15 years, with Electricité de France ("EDF"). Innergex is expecting revenues of approximately €23.5 million (or $34.8 million) and Adjusted EBITDA of approximately €18.2 million (or $26.9 million) for the first twelve months of operations.

The Rougemont-1 (36.1 MW) and Vaite (38.9 MW) wind farms are in commercial operation. The remaining wind project, Rougemont-2 (44.5 MW), should be fully commissioned in the fourth quarter of 2017.

DEVELOPMENT PROJECT AND COMMISSIONING ACTIVITIES

Commissioning Activities

	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project costs		Expected year-one	
					Estimated[1] ($M)	As at June 30 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
HYDRO (British Columbia)								
Boulder Creek	66.7	25.3	92.5	40	123.6	122.0	9.0	7.5

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary.

Boulder Creek

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 Commercial Operation Date (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 of the electricity the facility produces is covered by a 40-year fixed-price power purchase agreement with BC Hydro, which was obtained under that province's 2008 Clean Power Call Request for Proposals and 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 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 2015 fire 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.

Construction Activities

The total project costs for the Development Project were as follows:

PROJECTS UNDER CONSTRUCTION	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[1] ($M)	As at June 30 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
Wind (France)									
Rougemont-2	69.6	44.5	2017	100.3	15	101.2 [2]	73.4 [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.

Rougemont-2

The Rougemont-2 wind project was acquired during the second quarter of 2017. Construction was already under way at the time of the acquisition.

As at the date of this MD&A, all substantial civil works are complete, eight out of 16 wind turbines have already reached commercial operation, and delivery and installation has commenced on the remaining eight turbines. Full commissioning is expected in the fourth quarter of 2017.

PROSPECTIVE PROJECTS

With a combined potential net installed capacity of 3,560 MW (gross 3,940 MW), all the Prospective Projects are in the preliminary development stage.

Some Prospective Projects are targeted toward specific ongoing and future energy procurement processes in the provinces of New Brunswick, Alberta and Saskatchewan. In addition, in Saskatchewan, Innergex is part of the Yotin Wind Power Limited Partnership, which has been pre-qualified for Stage 2 of SaskPower's Wind Generation Capacity competition.

Other Prospective Projects are maintained or continue to be advanced and will be available for future requests for proposals yet-to-be-announced or are targeted toward negotiated power purchase agreements with public utilities or other creditworthy counterparties in Quebec, Alberta, British Columbia and Ontario or in other countries, such as France and the United States. There is no certainty that any Prospective Project will be realized.

OPERATING RESULTS

Electricity production in the last quarter was 92% of the LTA production due mainly to lower production from post-commissioning activities at the Upper Lillooet River, Boulder Creek and Mesgi'g Ugju's'n facilities during the quarter 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 12%, revenues 25% and Adjusted EBITDA 29%. 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 December 2016 and in 2017; they were partly offset by lower production at our British Columbia hydro facilities and our Quebec wind farms.

The Corporation's operating results for the three- and six-month periods ended June 30, 2017, are compared with the operating results for the same periods in 2016.

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.

Three months ended June 30	2017			2016		
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	222,102	214,050	104%	216,835	214,050	101%
Ontario	22,340	20,805	107%	14,907	20,805	72%
British Columbia	748,622	804,953	93%	735,420	610,738	120%
United States	9,709	16,956	57%	20,766	16,956	122%
Subtotal	1,002,773	1,056,764	95%	987,928	862,549	115%
WIND						
Quebec	234,748	278,561	84%	151,822	142,806	106%
France	72,904	89,487	81%	22,283	27,535	81%
Subtotal	307,652	368,048	84%	174,105	170,341	102%
SOLAR						
Ontario	12,356	12,288	101%	14,418	12,375	117%
Total	1,322,781	1,437,100	92%	1,176,451	1,045,265	113%

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 three-month period ended June 30, 2017, the Corporation's facilities produced 1,322,781 MWh of electricity or 92% of the LTA of 1,437,100 MWh. Overall, the hydroelectric facilities produced 95% of their LTA due mainly to lower production from post-commissioning activities at the Upper Lillooet River and Boulder Creek facilities during the quarter, partly offset by above-average water flows in Quebec and Ontario. Overall, the wind farms produced 84% of their LTA due to lower production from post-commissioning activities at the Mesgi'g Ugju's'n facility and to the below-average wind regimes in Quebec and France. The Stardale solar farm produced 101% of its LTA due to an average solar regime. For more information on operating segment results, please refer to the Segment Information section.

The 12% production increase over the same period last year is due mainly to the contribution of the recently commissioned or acquired facilities, which was partly offset by lower production at most of our British Columbia hydro facilities and to lower production at our Quebec wind farms.

Six months ended June 30	2017			2016		
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	355,588	338,220	105%	351,087	338,220	104%
Ontario	45,864	45,099	102%	37,063	45,099	82%
British Columbia	917,352	1,006,417	91%	1,018,849	790,533	129%
United States	16,437	24,883	66%	28,898	24,883	116%
Subtotal	1,335,241	1,414,619	94%	1,435,897	1,198,735	120%
WIND						
Quebec	538,796	645,575	83%	360,416	356,410	101%
France	150,857	178,071	85%	22,283	27,535	81%
Subtotal	689,653	823,646	84%	382,699	383,945	100%
SOLAR						
Ontario	20,159	19,469	104%	22,242	19,606	113%
Total	2,045,053	2,257,734	91%	1,840,838	1,602,286	115%

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 six-month period ended June 30, 2017, the Corporation's facilities produced 2,045,053 MWh of electricity or 91% of the LTA of 2,257,734 MWh. Overall, the hydroelectric facilities produced 94% of their LTA due mainly to lower production from post-commissioning activities at the Upper Lillooet River and Boulder Creek facilities during the period and below-average water flows in British Columbia, partly offset by above-average water flows in Quebec and Ontario. Overall, the wind farms produced 84% of their LTA due to lower production from post-commissioning activities at the Mesgi'g Ugju's'n facility and below-average wind regimes in Quebec and France. The Stardale solar farm produced 104% 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 11% production increase over the same period last year is due mainly to the contribution of the recently commissioned or acquired facilities, which was partly offset by lower production at most of our British Columbia hydro facilities and to lower production at our Quebec wind farms.

The overall performance of the Corporation's facilities for the period ended June 30, 2017, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind and solar power generation.

Financial Results

	Three months ended June 30				Six months ended June 30			
	2017		2016		2017		2016	
Revenues	109,530	100.0%	87,784	100.0%	184,056	100.0%	150,265	100.0%
Operating expenses	17,215	15.7%	14,218	16.2%	33,304	18.1%	23,616	15.7%
General and administrative expenses	4,757	4.3%	3,945	4.5%	9,335	5.1%	7,632	5.1%
Prospective project expenses	1,638	1.5%	2,758	3.1%	4,556	2.5%	4,475	3.0%
Adjusted EBITDA	85,920	78.4%	66,863	76.2%	136,861	74.4%	114,542	76.2%
Finance costs	39,064		24,608		68,361		44,102	
Other net revenues	(413)		(233)		(772)		(407)	
Depreciation and amortization	31,964		22,135		61,546		41,572	
Share of earnings of joint ventures (note 1)	(1,821)		(475)		(2,537)		(24)	
Unrealized net loss (gain) on financial instruments	470		(2,145)		(4,605)		(3,432)	
Income taxes expenses	2,556		7,296		3,102		9,858	
Net earnings	14,100		15,677		11,766		22,873	
Net earnings attributable to:								
Owners of the parent	14,567		14,381		17,023		22,713	
Non-controlling interests	(467)		1,296		(5,257)		160	
	14,100		15,677		11,766		22,873	
Basic net earnings per share ($)	0.12		0.12		0.13		0.19	

1. 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

For the three-month period ended June 30, 2017, the Corporation recorded revenues of $109.5 million, compared with $87.8 million for the three-month period ended June 30, 2016. This 25% increase is attributable mainly to the contribution of the Mesgi'g Ugju's'n wind farm and Big Silver Creek hydro facility commissioned in 2016 and of the Upper Lillooet River and Boulder Creek hydro facilities commissioned in 2017 as well as to the acquisition of the Montjean, Theil-Rabier, Yonne, Rougemont 1-2 and Vaite wind facilities in France in 2016 and 2017, which was partly offset by lower production at our British Columbia hydro facilities and at our Quebec wind farms.

For the six-month period ended June 30, 2017, the Corporation recorded revenues of $184.1 million, compared with $150.3 million for six-month period ended June 30, 2016. This 22% increase is attributable mainly to the facilities commissioned in 2016 and 2017 and the acquisitions of wind facilities in France in 2016 and 2017, which was partly offset by lower production at most of our British Columbia hydro facilities and at our Quebec wind farms.

Expenses

Operating expenses consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes and royalties. For the three- and six-month periods ended June 30, 2017, the Corporation recorded operating expenses of $17.2 million and $33.3 million respectively ($14.2 million and $23.6 million in 2016). This 21% increase for the quarter and 41% increase for the six-month period are attributable mainly to the commissioning of the Mesgi'g Ugju's'n wind farm in December 2016, the Big Silver Creek hydro facility in July 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 between April 2016 and May 2017, partly offset by a decrease in operating expenses for most British Columbia hydro facilities due to lower production levels compared with last year. Operating expenses for the six-month period 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 its 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 three- and six-month periods ended June 30, 2017, general and administrative expenses totalled $4.8 million and $9.3 million respectively ($3.9 million and $7.6 million in 2016). The 21% increase for the quarter and 22% increase for the six-month period stem mainly from the greater number of facilities in operation.

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 three-month period ended June 30, 2017, prospective project expenses totalled $1.6 million ($2.8 million in 2016). This 41% decrease stems partly from more time and effort being devoted to closing the Rougemont 1-2 and Vaite acquisition and to the costs being classified as transaction costs upon closing. For the six-month period ended June 30, 2017, prospective project expenses totalled $4.6 million ($4.5 million in 2016). The 2% increase is related 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 advancement of a number of prospective projects, partly offset by more time and effort being devoted to closing the Yonne, Rougemont 1-2 and Vaite acquisitions and by the costs being classified as transaction costs upon closing.

Adjusted EBITDA

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.

For the three- and six-month periods ended June 30, 2017, the Corporation recorded Adjusted EBITDA of $85.9 million and $136.9 million respectively compared with $66.9 million and $114.5 million for the same periods last year. These increases of 29% for three-month period and 19% for the six-month period are due mainly to the production and revenues from new facilities, partly offset by higher operating expenses and general and administrative expenses. The three-month period Adjusted EBITDA was also positively impacted by lower prospective expenses. The Adjusted EBITDA Margin increased from 76.2% to 78.4% for the quarter due mainly to lower prospective expenses and an increase in revenues net of operating expenses. The Adjusted EBITDA Margin decreased from 76.2% to 74.4% for the six-month period due mainly to the payment related to water rights for 2011 and 2012 in British Columbia made in the first quarter of 2017.

Finance Costs

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. For the three-month period ended June 30, 2017, finance costs totalled $39.1 million ($24.6 million in 2016). The increase is due mainly to expenses related to recently commissioned or acquired facilities (the Mesgi'g Ugju's'n wind farm, the Big Silver Creek, the Upper Lillooet River and Boulder Creek hydroelectric facilities commissioned respectively in December 2016, July 2016, March 2017 and May 2017, and the Montjean, Theil-Rabier, Yonne, Rougemont 1-2 and Vaite wind facilities in France acquired in December 2016, February 2017 and May 2017).

For the six-month period ended June 30, 2017, finance costs totalled $68.4 million ($44.1 million in 2016). The increase is due mainly to expenses related to the recently commissioned or acquired facilities.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 4.42% as at June 30, 2017 (4.79% as at December 31, 2016).

Depreciation and Amortization

For the three- and six-month periods ended June 30, 2017, depreciation and amortization expenses totalled $32.0 million and $61.5 million, respectively ($22.1 million and $41.6 million in 2016). These increases are attributable mainly to the Mesgi'g Ugju's'n wind farm commissioned in December 2016, the Big Silver Creek hydro facility commissioned in July 2016, the Upper Lillooet River hydro facility commissioned in March 2017 and the Boulder Creek hydro facility commissioned in May 2017 and to the French wind farms acquired in April 2016, December 2016, February 2017 and May 2017.

Share of Earnings of Joint Ventures

For the three- and six-month periods ended June 30, 2017, the Corporation recorded a share of net earnings of joint ventures of $1.8 million and $2.5 million respectively (share of net earnings of $0.5 million and $0.02 million in 2016). Please refer to the Investments in Joint Ventures section for more information.

Unrealized Net Loss (Gain) on Financial Instruments

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.

For the three- and six-month periods ended June 30, 2017, the Corporation recognized a $0.5 million unrealized net loss on financial instruments and a $4.6 million unrealized net gain on financial instruments respectively. The unrealized net loss for the quarter is attributable to an unrealized net loss on the foreign exchange rate swap due to an unfavourable change in the CAD-EUR foreign exchange rate, which was mostly offset by a gain on the conversion of an intragroup loan and the amortization of the accumulated losses from the period prior to when hedge accounting was used. The unrealized net gain for the six-month period 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 periods last year, the Corporation recognized an unrealized net gain on derivative financial instruments of $2.1 million and $3.4 million due mainly to the increase in benchmark interest rates since December 31, 2015.

For the period ended June 30, 2017, the Corporation had no Derivatives to be settled upon the closing of project financing, as all the project financings were put in place in prior periods.

Income Tax Expense

For the three-month period ended June 30, 2017, the Corporation recorded a current income tax expense of $0.9 million ($0.8 million in 2016) and a deferred income tax expense of $1.7 million (deferred income tax expense of $6.5 million in 2016). The $4.8 million decrease in the deferred income tax expense is due mainly to the decrease in earnings before income taxes and the decrease in taxable temporary differences in relation to investments in subsidiaries and joint ventures.

For the six-month period ended June 30, 2017, the Corporation recorded a current income tax expense of $1.7 million ($1.5 million in 2016) and a deferred income tax expense of $1.4 million (deferred income tax expense of $8.4 million in 2016). The $7.0 million decrease in the deferred income tax expense is again due mainly to the decrease in earnings before income taxes and the decrease in taxable temporary differences in relation to investments in subsidiaries and joint ventures.

Net Earnings

For the three-month period ended June 30, 2017, the Corporation recorded net earnings of $14.1 million (basic and diluted net earnings of $0.12 per share), compared with net earnings of $15.7 million (basic and diluted net earnings of $0.12 per share) in 2016. The $1.6 million decrease in net earnings can be explained mainly by this year's below-average production compared with last year's above-average production, which explains the net earnings decrease as opposed to the increase in revenues. As a result, the $14.5 million increase in finance costs, the $9.8 million increase in depreciation and amortization related primarily to the greater number of operating facilities and the $2.6 million change in the unrealized net loss on derivative financial instruments were only partly offset by the $19.1 million increase in Adjusted EBITDA, the $4.7 million decrease in income tax expenses and the $1.3 million increase in share of earnings of joint ventures.

For the six-month period ended June 30, 2017, the Corporation recorded net earnings of $11.8 million (basic and diluted net earnings of $0.13 per share), compared with net earnings of $22.9 million (basic and diluted net earnings of $0.19 per share) in 2016. The $11.1 million decrease in net earnings can be explained mainly by this year's below-average production compared with last year's above-average production, which explains the decrease in net earnings as opposed to the increase in revenues. As a result, the $24.3 million increase in finance costs and the $20.0 million increase in depreciation and amortization were only partly offset by the $22.3 million increase in Adjusted EBITDA, the $6.8 million decrease in income tax expenses and the $2.5 million share of earnings of joint ventures.

Main items explaining the change in net earnings for the three-month period ended June 30, 2017, compared with the net earnings for the corresponding period in 2016		
Main items – Positive impact	Change	Explanation
Adjusted EBITDA	19,057	Due mainly to the production and revenues from new facilities, partly offset by higher operating expenses and general and administrative expenses.
Deferred income tax expense	4,754	Due mainly to the decrease in earnings before income taxes and the decrease in taxable temporary differences related to investments in subsidiaries and in joint ventures.
Main items – Negative impact	Change	Explanation
Finance costs	14,456	Due mainly to expenses related to recently commissioned or acquired facilities.
Depreciation and amortization	9,829	Due mainly to the recently commissioned or acquired facilities.
Unrealized net loss (gain) on financial instruments	2,615	Due to an unrealized net loss on the foreign exchange rate swap compared with a gain on interest swaps in the comparative period.

Main items explaining the change in net earnings for the six-month period ended June 30, 2017, compared with the net earnings for the corresponding period in 2016		
Main items – Positive impact	Change	Explanation
Adjusted EBITDA	22,319	Due mainly to the production and revenues from new facilities, partly offset by higher operating expenses and general and administrative expenses.
Share of earnings of joint ventures	2,513	Mainly due to unrealized net gains on financial instruments for both Umbata Falls L.P. and Viger-Denonville L.P.
Deferred income tax expense	7,027	Due mainly to the decrease in earnings before income taxes and the decrease in taxable temporary differences related to investments in subsidiaries and in joint ventures.
Main items – Negative impact	Change	Explanation
Finance costs	24,259	Due mainly to expenses related to recently commissioned or acquired facilities.
Depreciation and amortization	19,974	Due mainly to the recently commissioned or acquired facilities.

Non-controlling Interests

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. For the three-month period ended June 30, 2017, the Corporation allocated losses of $0.5 million to non-controlling interests (earnings of $1.3 million in 2016) mainly due to a loss in Innergex Europe due to weak revenues during the period and an unrealized loss on derivative financial instruments and to a loss in Creek Power due to lower production from post-commissioning activities at the Upper Lillooet River and Boulder Creek facilities, partly offset by revenues allocated to HHLP and MU during the period.

For the six-month period ended June 30, 2017, the Corporation allocated losses of $5.3 million to non-controlling interests (earnings of $0.2 million in 2016) mainly due to losses at Kwoiek, Creek Power, HHLP and Innergex Europe related to lower production, to an unrealized loss on derivative financial instruments for Innergex Europe and to the HHLP payment related to water rights for 2011 and 2012, partly offset by revenues at MU.

Number of Common Shares Outstanding

Weighted average number of common shares outstanding (000s)	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Weighted average number of common shares	108,431	107,318	108,386	105,657
Effect of dilutive elements on common shares[1]	995	996	976	812
Diluted weighted average number of common shares	109,426	108,314	109,362	106,469

1. During the three- and six-month periods ended June 30, 2017, 3,331,684 of the 3,457,432 stock options (all of the 3,425,684 for the three- and six-month periods ended June 30, 2016) were dilutive. During the three- and six-month periods ended June 30, 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 periods in 2016).

The Corporation's Equity Securities

As at	August 3, 2017	June 30, 2017	June 30, 2016
Number of common shares	108,519,412	108,443,695	107,972,113
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	3,457,432	3,457,432	3,425,684

As at the date of this MD&A and since June 30, 2017, the increase in the number of common shares of the Corporation is attributable to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at June 30, 2017, the increase in the number of common shares since June 30, 2016, is attributable mainly to the issuance of 94,000 shares following the exercise of stock options and to 377,582 shares related to the DRIP.

LIQUIDITY AND CAPITAL RESOURCES

For the six-month period ended June 30, 2017, the Corporation generated cash flows from operating activities of $70.6 million, compared with cash flows of $58.9 million for the same period last year. During this six-month period, the Corporation generated funds from financing activities of $112.2 million and used funds for investing activities of $155.5 million, mainly to pay for the acquisition of the Yonne, Rougemont 1-2 and Vaite wind farms and the construction of its Upper Lillooet River and Boulder Creek facilities, partly offset by a decrease of restricted cash and short-term investments. As at June 30, 2017, the Corporation had cash and cash equivalents amounting to $82.8 million, compared with $56.2 million as at December 31, 2016.

Cash Flows from Operating Activities

For the six-month period ended June 30, 2017, cash flows generated by operating activities totalled $70.6 million ($58.9 million generation in 2016). The increase of $11.7 million is attributable to the $22.3 million increase in Adjusted EBITDA and a positive variation in non-cash operating working capital items, which was partly offset by higher interest paid.

Cash Flows from Financing Activities

For the six-month period ended June 30, 2017, cash flows generated by financing activities totalled $112.2 million (compared with $126.9 million generated in 2016). The cash flows from the financing activities are attributable mainly to a $137.1 million net increase in long-term debt partly offset by the payment of $34.5 million in dividends.

The $137.1 million net increase in long-term debt is attributable mainly to drawings made on the revolving credit facility related to the acquisition of the Yonne, Rougemont 1-2 and Vaite facilities, drawings made on Mesgi'g Ugju's'n project financing and the raising of subordinated debt from a French infrastructure fund via the French subsidiaries created for the acquisition of seven 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.

Use of Financing Proceeds	Six months ended June 30	
	2017	2016
Proceeds from issuance of long-term debt (including revolving credit facility)	300,866	488,206
Repayment of long-term debt (including revolving credit facility)	(163,203)	(381,249)
Payment of deferred financing costs	(613)	(1,998)
Subtotal: net increase in long-term debt	137,050	104,959
Proceeds from issuance of common shares	—	50,000
Investments from non-controlling interests	10,913	6,392
Generation of financing proceeds	147,963	161,351
Business acquisitions	(112,834)	(102,795)
Decrease of restricted cash and short-term investments	17,639	145,207
Net funds withdrawn from the reserve accounts	55	171
Additions to property, plant and equipment	(65,524)	(204,135)
Reductions of (additions) other long-term assets	71	(14,626)
Net use of financing proceeds	(160,593)	(176,178)
Reduction in working capital	(12,630)	(14,827)

During the six-month period ended June 30, 2017, the Corporation borrowed a net amount of $137.1 million and Desjardins Group Pension Plan invested $10.9 million, mainly to pay for the acquisition of the Yonne, Rougemont 1-2 and Vaite wind facilities in February and May 2017. The net amount borrowed was also used for the construction of the Mesgi'g Ugju's'n facility. The Corporation used $17.6 million in restricted cash mainly to continue construction of the Upper Lillooet River and Boulder Creek facilities.

Cash Flows from Investing Activities

For the six-month period ended June 30, 2017, cash flows used by investing activities amounted to $155.5 million ($164.3 million in 2016). During the period, the main investing activities impacting cash flows were as follows: additions to property, plant and equipment accounted for a $65.5 million outflow ($204.1 million outflow in 2016); fluctuations in restricted cash and short-term investments accounted for a $17.6 million inflow ($145.2 million inflow in 2016); additions to other long-term assets accounted for a small inflow ($14.6 million outflow in 2016); and business acquisitions accounted for a $112.8 million net outflow ($102.8 million outflow in 2016) for the acquisition of the Yonne, Rougemont 1-2 and Vaite facilities in February and May 2017.

Cash and Cash Equivalents

As at June 30, 2017, the Corporation had cash and cash equivalents amounting to $82.8 million ($56.2 million as at December 31, 2016). For the six-month period ended June 30, 2017, cash and cash equivalents increased by $26.6 million (increased by $21.5 million in 2016) as a net result of its operating, financing and investing activities.

DIVIDENDS

The following dividends were declared by the Corporation:

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Dividends declared on common shares[1]	17,893	17,276	35,775	33,917
Dividends declared on common shares ($/share)	0.165	0.160	0.330	0.320
Dividends declared on Series A Preferred Shares	767	767	1,533	1,533
Dividends declared on Series A Preferred Shares ($/share)	0.2255	0.2255	0.4510	0.4510
Dividends declared on Series C Preferred Shares	719	719	1,438	1,438
Dividends declared on Series C Preferred Shares ($/share)	0.359375	0.359375	0.718750	0.718750

1. The increase in dividends declared on common shares is attributable to the issuance of 94,000 shares following the exercise of stock options in the third quarter of 2016 as well as to the issuance of 377,582 shares under the DRIP.

The following dividends will be paid by the Corporation on October 16, 2017:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
08/03/2017	9/29/2017	10/16/2017	0.1650	0.2255	0.359375

On February 23, 2017, the Board of Directors increased the annual dividend from $0.64 to $0.66 per common share, payable quarterly.

FINANCIAL POSITION

As at June 30, 2017, the Corporation had $4,077 million in total assets, $3,600 million in total liabilities, including $3,070 million in long-term debt, and $477.8 million in shareholders' equity. The Corporation also had a working capital ratio of 1.13:1.00 (1.14:1.00 as at December 31, 2016). In addition to cash and cash equivalents amounting to $82.8 million, the Corporation had restricted cash and short-term investments of $81.8 million and reserve accounts of $49.7 million. The explanations below highlight the most significant changes in the statement of financial position items during the six-month period ended June 30, 2017.

Assets

Highlights of significant changes in total assets during the six-month period ended June 30, 2017

- A $356.2 million increase in property, plant and equipment, due mainly to the acquisition of the Yonne, Rougemont 1-2 and Vaite facilities in 2017 and the construction of the Upper Lillooet River and Boulder Creek facilities, partly offset by the depreciation for the period;
- A $82.6 million increase in intangible assets, due to the acquisition of the Yonne, Rougemont 1-2 and Vaite facilities, partly offset by the amortization for the period;

Working Capital Items

Working capital was positive at $34.0 million, as at June 30, 2017, with a working capital ratio of 1.13:1.00. 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 higher cash and cash equivalents and higher accounts receivable, partly offset by a decrease in restricted cash and short-term investments, higher accounts payable and current portion of long-term debt due mainly to the recently commissioned or acquired facilities and higher derivative financial instruments.

The Corporation considers its current level of working capital to be sufficient to meet its needs. The Corporation can also use its $425.0 million revolving term credit facility if necessary. As at June 30, 2017, the Corporation had drawn $270.4 million and US$13.9 million as cash advances, while $38.1 million had been used for issuing letters of credit, leaving $95.9 million available.

Cash and cash equivalents amounted to $82.8 million as at June 30, 2017, compared with $56.2 million as at December 31, 2016. The increase stems from higher production and a greater number of facilities in operation and to the cash acquired with the Yonne facility in 2017.

Restricted cash and short-term investments amounted to $81.8 million as at June 30, 2017, compared with $89.7 million as at December 31, 2016. The decrease stems mainly from the 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 loan, partly offset by the cash cumulated and not distributed since the commissioning of the Mesgi'g Ugju's'n facility, as the non-recourse construction and term project financing is not converted into a term loan, by drawings on the Montjean and Theil-Rabier project financings and by the restricted cash acquired with Rougemont 1-2 and Vaite facilities.

Accounts receivable increased from $98.8 million to $121.4 million between December 31, 2016, and June 30, 2017, due mainly to a better month of June 2017 compared with December 2016 for most of our British Columbia facilities, to the commissioning of the Upper Lillooet River and Boulder Creek hydro facilities and the Mesgi'g Ugju's'n wind facility and to the acquisition of the Yonne, Rougemont 1-2 and Vaite wind facilities.

Accounts payable and other payables from December 31, 2016, to June 30, 2017, increased from $85.9 million to $89.5 million, due mainly to the accounts payable acquired with the Yonne, Rougemont 1-2 and Vaite facilities and the construction costs for Mesgi'g Ugju's'n, 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 $131.6 million as at June 30, 2017, compared with $99.4 million as at December 31, 2016. The increase stems mainly from the portion of the Mesgi’g Ugju’s’n facility's debt payable in the short-term and its substation loan as well as from the acquisition of the Yonne, Rougemont 1-2 and Vaite facilities. The sum of $49.3 million will be paid out of the accounts receivable from Hydro-Québec for the Mesgi'g Ugju's'n substation reimbursement.

Reserve Accounts

Reserve accounts consist of a hydrology/wind reserve, 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, established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. The Corporation had $49.7 million in long-term reserve accounts as at June 30, 2017, compared with $49.5 million as at December 31, 2016. The increase is mainly due to drawings on reserve accounts, partly offset by mandatory investments during the period.

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

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 June 30, 2017, the Corporation had $3,056 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 and Vaite 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 $627.5 million in intangible assets as at June 30, 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 and Vaite facilities, partly offset by the amortization.

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 $840.8 million as at June 30, 2017.

Overall, Derivatives had a net negative value of $64.3 million at June 30, 2017 (net negative value of $60.1 million 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 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 June 30, 2017, accrual for acquisition of long-term assets was $2.2 million ($37.4 million as at December 31, 2016). The $35.2 million decrease results mainly from payments made in relation to the Mesgi'g Ugju's'n facility and the Montjean and Theil-Rabier facilities acquired in December 2016, for which drawings were made from the long-term financing in place.

Long-Term Debt

As at June 30, 2017, long-term debt totalled $3,070 million ($2,607 million as at December 31, 2016). The $463.2 million increase results mainly from the addition of the Yonne, Rougemont 1-2 and Vaite facilities, additional drawings on Innergex's credit facility and Mesgi'g Ugju's'n, Theil-Rabier and Montjean financings, the issuance of a debenture carrying an 8.0% interest rate to Desjardins for its investment in the acquisition of the Yonne, Rougemont 1-2 and Vaite facilities and the addition of the subordinated debt financing for two of the French subsidiaries, partly offset by the 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 facility. 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 will be put in place.

As at June 30, 2017, 92% 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.

Shareholders' Equity

As at June 30, 2017, the Corporation's shareholders' equity totalled $477.8 million, including $20.2 million of non-controlling interests, compared with $485.2 million as at December 31, 2016, and which included $14.7 million of non-controlling interests. This $7.4 million decrease in total shareholders' equity is attributable mainly to $38.7 million in dividends declared on common and preferred shares, and partly offset by the recognition of $11.8 million in net earnings, the recognition of other items of comprehensive income totaling $5.9 million, a $9.9 million net investment of non-controlling interest and a $3.7 million in shares issued under the DRIP.

Off-Balance-Sheet Arrangements

As at June 30, 2017, the Corporation had issued letters of credit totaling $95.1 million to meet its obligations under its various PPAs and other agreements. Of this amount, $38.1 million was issued under its revolving term credit facility, for the most part on a temporary basis during the construction of the Upper Lillooet River and Boulder Creek facilities which ended recently, with the remainder being issued under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $27.0 million in corporate guarantees used mainly to support the performance of the Brown Lake and Miller Creek hydroelectric facilities and the construction of the Mesgi'g Ugju's'n facility and to guarantee the long-term currency hedging instruments of its European operations.

FREE CASH FLOW AND PAYOUT RATIO

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.

Free Cash Flow and Payout Ratio calculation	Trailing 12 months ended June 30	
	2017	2016
Cash flows from operating activities	88,464	95,137
Add (Subtract) the following items:		
Changes in non-cash operating working capital items	46,837	8,727
Maintenance capital expenditures net of proceeds from disposals	(2,514)	(3,752)
Scheduled debt principal payments	(45,399)	(38,929)
Free Cash Flow attributed to non-controlling interests[1]	(8,496)	(4,645)
Dividends declared on Preferred shares	(5,942)	(6,533)
Adjust for the following elements:		
Transaction costs related to realized acquisitions	2,938	1,950
Realized losses on derivative financial instruments	—	26,984
Free Cash Flow	75,888	78,939
Dividends declared on common shares	70,383	66,201
Payout Ratio - before the impact of the DRIP	93%	84%
Dividends declared on common shares and paid in cash[2]	64,661	63,168
Payout Ratio - after the impact of the DRIP	85%	80%

1. 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.
2. 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.

For the trailing twelve-month period ended June 30, 2017, the Corporation generated Free Cash Flow of $75.9 million, compared with $78.9 million for the corresponding period last year. The decrease in Free Cash Flow is mainly due to greater scheduled debt principal payments and higher free cash flows attributed to non-controlling interests, partly offset by the increase in cash flows before changes in non-cash working capital items and the realized losses on derivative financial instruments . The realized loss on derivative financial instruments in the prior period was related to the settlement of the Mesgi'g Ugju's'n bond forwards contracts at the closing of the projects' financing. The Corporation also committed to investing more to pursue growth opportunities in new international markets, which also reduced cash flows from operating activities.

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 trailing twelve-month period ended June 30, 2017, the dividends on common shares declared by the Corporation amounted to 93% of Free Cash Flow, compared with 84% for the corresponding period last year. This negative impact is due mainly to lower free cash flow and higher dividend payments as a result of a 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, 94,000 shares following the exercise of stock options and 377,582 shares 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 trailing twelve-month period ended June 30, 2017, the Corporation incurred prospective project expenses of $10.4 million, compared with $9.2 million for the corresponding period last year. This 13% increase is attributable mainly to the advancement of a number of prospective projects and to pursuing opportunities in new international markets. Excluding these discretionary expenses, the Corporation's Payout Ratio would have been approximately 11% points lower for the twelve-month period ended June 30, 2017, and approximately 9% points lower for the prior twelve-month period.

Furthermore, the Corporation does not expect to require additional equity in order to complete its Rougemont-2 project under construction, 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.

SEGMENT INFORMATION

Geographic Segments

As at June 30, 2017, the Corporation had interests in 30 hydroelectric facilities, seven wind farms and one solar farm in Canada, 12 wind farms in Europe and one hydroelectric facility in the United States. The Corporation operates in three principal geographical areas, which are detailed below.

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Revenues				
Canada	99,865	83,300	164,354	145,129
Europe	8,845	2,812	18,325	2,812
United States	819	1,673	1,377	2,324
	109,529	87,785	184,056	150,265

As at	June 30, 2017	December 31, 2016
Non-current assets, excluding financial instruments and deferred tax assets		
Canada	2,991,989	3,005,720
Europe	759,586	318,924
United States	6,937	7,365
	3,758,512	3,332,009

Canada

For the three- and six-month periods ended June 30, 2017, the Corporation recorded revenues in Canada of $99.9 million and $164.4 million respectively compared with $83.3 million and $145.1 million last year. 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 was partly offset by lower revenues from most of our hydroelectric facilities across the country and from the Quebec wind farms.

For the period ended June 30, 2017, the decrease in non-current assets, excluding 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

For the three- and six-month periods ended June 30, 2017, the Corporation recorded revenues in Europe of $8.8 million and $18.3 million respectively compared with $2.8 million for each period last year. The increase in European revenues is attributable mainly to the facilities acquired on December 22, 2016, February 21, 2017, and May 24, 2017. The six-month period ended June 30, 2017, was also impacted by the acquisition of seven wind farms in France on April 15, 2016.

For the period ended June 30, 2017, the increase in non-current assets, excluding financial instruments and deferred income tax assets in Europe, stems from the Yonne wind facility acquired on February 21, 2017, and the Rougemont 1-2 and Vaite wind facilities acquired on May 24, 2017.

United States

For the three- and six-month periods ended June 30, 2017, the Corporation recorded revenues in the United States of $0.8 million and $1.4 million compared with $1.7 million and $2.3 million last year. The decrease in the United States revenues is attributable to a voluntary limitation in production of the Horseshoe Bend hydro facility due to unusually high volumes of water in order to prevent sand accumulation in the canal, which can damage the facility and be more costly to remove. For the period ended June 30, 2017, the decrease in non-current assets stems mainly from depreciation.

Operating Segments

As at June 30, 2017, the Corporation had four operating segments: hydroelectric generation, wind power generation, solar power generation and site development. For the segment descriptions, please refer to the Operating Segments section of the Corporation's Financial Review at December 31, 2016.

SUMMARY OPERATING RESULTS Three months ended June 30, 2017	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	1,002,773	304,101	12,356	3,551	1,322,781
Revenues	74,177	29,777	5,190	386	109,530
Expenses:					
Operating expenses	10,742	6,117	170	186	17,215
General and administrative expenses	2,744	1,939	33	41	4,757
Prospective project expenses	—	—	—	1,638	1,638
Adjusted EBITDA	60,691	21,721	4,987	(1,479)	85,920
Three months ended June 30, 2016					
Power generated (MWh)	987,928	174,105	14,418	—	1,176,451
Revenues	66,744	14,984	6,056	—	87,784
Expenses:					
Operating expenses	10,674	3,343	201	—	14,218
General and administrative expenses	2,032	1,204	40	669	3,945
Prospective project expenses	—	—	—	2,758	2,758
Adjusted EBITDA	54,038	10,437	5,815	(3,427)	66,863

SUMMARY OPERATING RESULTS Six months ended June 30, 2017	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	1,335,241	686,102	20,159	3,551	2,045,053
Revenues	108,535	66,669	8,466	386	184,056
Expenses:					
Operating expenses	21,481	11,292	345	186	33,304
General and administrative expenses	5,510	3,360	88	377	9,335
Prospective project expenses	—	—	—	4,556	4,556
Adjusted EBITDA	81,544	52,017	8,033	(4,733)	136,861
Six months ended June 30, 2016					
Power generated (MWh)	1,435,897	382,699	22,242	—	1,840,838
Revenues	109,184	31,739	9,342	—	150,265
Expenses:					
Operating expenses	17,784	5,473	359	—	23,616
General and administrative expenses	3,984	2,151	80	1,417	7,632
Prospective project expenses	—	—	—	4,475	4,475
Adjusted EBITDA	87,416	24,115	8,903	(5,892)	114,542

FINANCIAL POSITION As at June 30, 2017	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	—	—	—	8,269
Total assets	2,465,780	1,400,781	105,077	105,744	4,077,382
Total liabilities	2,120,652	1,273,742	110,085	95,061	3,599,540
Acquisition of property, plant and equipment during the period	4,222	284,234	12	102,776	391,244
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

Hydroelectric Generation Segment

For the three-month period ended June 30, 2017, this segment produced 95% of the LTA and generated revenues of $74.2 million compared with production at 115% of the LTA and revenues of $66.7 million last year. The revenue and production increases in this segment are due mainly to the contribution of the Big Silver Creek, Upper Lillooet River and Boulder Creek hydroelectric facilities, which began commercial operation in July 2016, March 2017 and May 2017 respectively. They were partly offset by lower production at most of our British Columbia hydro facilities during the quarter.

For the six-month period ended June 30, 2017, this segment produced 94% of the LTA and generated revenues of $108.5 million compared with production at 120% of the LTA and revenues of $109.2 million last year. The revenue and production decreases in this segment are due mainly to lower production at most of our British Columbia hydro facilities, partly offset by the contribution of the Big Silver Creek, Upper Lillooet River and Boulder Creek hydroelectric facilities commissioned between July 2016 and May 2017. Expenses in the period were higher due mainly to 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 its 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

For the three-month period ended June 30, 2017, this segment produced 84% of the LTA and generated revenues of $29.8 million compared with production at 102% of the LTA and revenues of $15.0 million for the same period last year. The decrease in the percentage of the LTA is due mainly to the lower wind regimes in Quebec. The revenue increase is due mainly to the commissioning of the Mesgi'g Ugju's'n wind farm and to the Montjean, Theil-Rabier, Yonne, Rougemont 1-2 and Vaite wind facilities acquired in December 2016, February 2017 and May 2017.

For the six-month period ended June 30, 2017, this segment produced 84% of the LTA and generated revenues of $66.7 million compared with production at 100% of the LTA and revenues of $31.7 million for the same period last year. The decrease in the percentage of the LTA is due mainly to the lower wind regimes in Quebec. The revenue increase is due mainly to the commissioning of the Mesgi'g Ugju's'n wind farm and to the wind facilities in France acquired in 2016 and 2017.

The increase in total assets since December 31, 2016, is mainly attributable to the acquisition of the Yonne, Rougemont 1 and Vaite facilities in February and May 2017 respectively and to the cash cumulated and not distributed since the commissioning of the Mesgi'g Ugju's'n, as the non-recourse construction and term project financing is not converted in a term loan. The increase 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 acquisition of the Yonne, Rougemont 1 and Vaite facilities in February and May 2017, which was partly offset by the scheduled repayment of long-term debt.

Solar Power Generation Segment

For the three-month period ended June 30, 2017, this segment produced 101% of the LTA and generated revenues of $5.2 million compared with production at 117% of the LTA and revenues of $6.1 million for the same period last year. The decrease in revenues can be explained by lower solar irradiation than last year.

For the six-month period ended June 30, 2017, this segment produced 104% of the LTA and generated revenues of $8.5 million compared with production at 113% of the LTA and revenues of $9.3 million for the same period 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

For the three- and six-month periods ended June 30, 2017, site development net expenses were $1.5 million and $4.7 million respectively compared with $3.4 million and $5.9 million in 2016. These decreases stem partly from more time and effort being devoted to closing the Yonne, Rougemont 1-2 and Vaite acquisitions and their costs being classified as transaction costs upon closing.

The decrease in total assets since December 31, 2016, stems mainly from the Upper Lillooet River and Boulder Creek projects being transferred from the Site Development Segment to the Hydroelectric Generation Segment following their commissioning in March and May 2017, partly offset by the addition of the Rougemont-2 wind project acquired in 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, partly offset by the addition of the Rougemont-2 wind project acquired in May 2017.

QUARTERLY FINANCIAL INFORMATION

	Three months ended			
(in millions of dollars, unless otherwise stated)	June 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sept. 30, 2016
Power generated (MWh)	1,322,781	722,273	848,967	831,840
Revenues	109.5	74.5	73.3	69.3
Adjusted EBITDA	85.9	50.9	50.3	51.2
Realized and unrealized net (loss) gain on financial instruments	(0.5)	5.1	2.2	(1.3)
Impairment of project development costs	—	—	—	—
Net earnings (loss)	14.1	(2.3)	8.8	0.4
Net earnings attributable to owners of the parent	14.6	2.5	9.8	3.4
Net earnings attributable to owners of the parent ($ per share – basic and diluted)	0.12	0.01	0.08	0.02
Dividends declared on preferred shares	1.5	1.5	1.5	1.5
Dividends declared on common shares	17.9	17.9	17.3	17.3
Dividends declared on common shares, $ per share	0.165	0.165	0.160	0.160

	Three months ended			
(in millions of dollars, unless otherwise stated)	June 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sept. 30, 2015
Power generated (MWh)	1,176,451	664,387	647,062	777,975
Revenues	87.8	62.5	56.3	62.7
Adjusted EBITDA	66.9	47.7	38.8	48.6
Realized and unrealized net gain (loss) on financial instruments	2.2	1.3	2.0	(2.7)
Impairment of project development costs	—	—	(51.7)	—
Net earnings (loss)	15.7	7.2	(34.4)	1.3
Net earnings (loss) attributable to owners of the parent	14.4	8.3	(30.6)	5.8
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.12	0.07	(0.31)	0.04
Dividends declared on preferred shares	1.5	1.5	1.8	1.8
Dividends declared on common shares	17.3	16.6	16.1	16.2
Dividends declared on common shares, $ per share	0.160	0.160	0.155	0.155

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 61% 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 impairment of project development costs and 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.

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 June 30	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	51,190	37,823	135%	41,284	37,823	109%
Viger-Denonville	14,576	15,450	94%	14,864	15,450	96%

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

Six months ended June 30	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	77,118	54,750	141%	69,393	54,750	127%
Viger-Denonville	35,004	35,750	98%	36,632	35,750	102%

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

Umbata Falls, L.P.

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

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Revenues	4,358	3,506	6,566	5,894
Operating and general and administrative expenses	234	231	450	466
Adjusted EBITDA	4,124	3,275	6,116	5,428
Finance costs	608	633	1,208	1,263
Other net revenues	(9)	(8)	(17)	(16)
Depreciation and amortization	1,004	1,004	2,009	2,008
Unrealized net (gain) loss on financial instruments	(812)	676	(779)	2,124
Net earnings and comprehensive income	3,333	970	3,695	49

For the three- and six-month periods ended June 30, 2017, production was 135% and 141% of the LTA respectively due mainly to above-average water flows during the period.

The increases in Adjusted EBITDA for the three- and six-month periods ended June 30, 2017, are due mainly to higher production levels compared with the same period last year. The increases are also attributable to operating and general and administrative expenses, which were comparable to last year despite higher production volumes.

For the three- and six-month periods ended June 30, 2017, Umbata Falls L.P. recorded net earnings and comprehensive income of $3.3 million and $3.7 million respectively compared with $1.0 million and $0.05 million in net earnings and comprehensive income for the same period last year. The increases reflect the impact of an unrealized net gain on financial instruments as opposed to a net loss for the same period last year.

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

As at	June 30, 2017	December 31, 2016
Current assets	4,403	2,090
Non-current assets	62,651	64,647
	67,054	66,737
Current liabilities	3,791	3,033
Non-current liabilities	43,483	46,173
Partners' equity	19,780	17,531
	67,054	66,737

As at June 30, 2017, the increase in partners' equity stems from the recognition of $3.7 million in net earnings and comprehensive income, partly offset by a $1.4 million distribution to the partners. 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 $42.3 million used to hedge the interest rate on the Umbata Falls loan had a net negative value of $6.8 million at June 30, 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.

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Revenues	2,185	2,222	5,247	5,475
Operating and general and administrative expenses	433	434	947	940
Adjusted EBITDA	1,752	1,788	4,300	4,535
Finance costs	866	907	1,740	1,836
Other net revenues	(9)	(8)	(17)	(11)
Depreciation and amortization	730	731	1,459	1,462
Unrealized net gain on financial instruments	(211)	(166)	(335)	(289)
Net earnings	376	324	1,453	1,537
Other comprehensive income (loss)	646	(768)	518	(2,220)
Total other comprehensive income (loss)	1,022	(444)	1,971	(683)

For the three- and six-month periods ended June 30, 2017, production was 94% and 98% of the LTA, due mainly to slightly below-average wind regime. The decrease in Adjusted EBITDA is due mainly to lower production levels and revenues than for the same periods last year.

For the three-month period ended on June 30, 2017, the increase in net earnings compared with the same period last year is due mainly to lower finance costs and a higher unrealized net gain on financial instruments. For the six-month period ended June 30, 2017, the decrease in net earnings compared with last year is due mainly to lower revenues and production levels, partly offset by lower finance costs and a higher unrealized net gain on financial instruments.

For the three- and six-month periods ended on June 30, 2017, the increases in other comprehensive income are mainly attributable to unrealized net gains on financial instruments.

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

As at	June 30, 2017	December 31, 2016
Current assets	2,091	2,249
Non-current assets	55,135	56,583
	57,226	58,832
Current liabilities	4,130	4,375
Non-current liabilities	51,997	54,223
Partners' equity	1,099	234
	57,226	58,832

As at June 30, 2017, the increase in partners' equity stems mainly from the recognition of $2.0 million in net earnings and other comprehensive income, partly offset by a $1.1 million distribution to the partners. 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 $50.3 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $4.7 million at June 30, 2017 (negative $5.5 million at December 31, 2016).

NON-WHOLLY OWNED SUBSIDIARIES

Montjean, Theil-Rabier, Yonne, Rougemont 1-2 and Vaite facilities

The following 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 Montjean, Theil-Rabier, Yonne, Rougemont 1-2 and Vaite is set out below:

Summary Statements of Earnings and Comprehensive (Loss) Income – Montjean, Theil-Rabier

	Three months ended June 30, 2017	Six months ended June 30, 2017
Revenues	1,955	3,964
Adjusted EBITDA	1,423	3,074
Net loss	(933)	(827)
Other comprehensive income	5	6
Total comprehensive loss	(928)	(821)

Summary Statements of Financial Position – Montjean, Theil-Rabier

As at	June 30, 2017	December 31, 2016
Current assets	13,048	12,971
Non-current assets	84,754	84,451
	97,802	97,422
Current liabilities	14,984	16,529
Non-current liabilities	66,597	64,592
Equity	16,221	16,301
	97,802	97,422

Summary Statements of Earnings and Comprehensive Income (Loss) – Yonne

	Three months ended June 30, 2017	Period of 130 days ended June 30, 2017
Revenues	1,915	3,465
Adjusted EBITDA	1,593	2,836
Net loss	(232)	(546)
Other comprehensive income	382	374
Total comprehensive income (loss)	150	(172)

Summary Statement of Financial Position – Yonne

As at	June 30, 2017
Current assets	10,476
Non-current assets	146,743
	157,219
Current liabilities	4,678
Non-current liabilities	130,371
Equity	22,170
	157,219

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

	Period of 37 days ended June 30, 2017
Revenues	1,524
Adjusted EBITDA	1,018
Net loss	(583)
Other comprehensive income	800
Total comprehensive income	217

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

As at	June 30, 2017
Current assets	18,111
Non-current assets	305,356
	323,467
Current liabilities	27,242
Non-current liabilities	258,334
Equity	37,891
	323,467

ACCOUNTING CHANGES

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 course in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. They also began reviewing the application of the standard to the Corporation. .

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 course 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.

SUBSEQUENT EVENTS

Final Agreement to Acquire Two Wind Projects in France

On July 5, 2017, the Corporation and Desjardins Group Pension Plan announced that a final agreement had been signed with BayWa r.e. to purchase two wind projects in France with a total aggregate installed capacity of 43 MW. The electricity to be produced will be sold under power purchase agreements at a fixed price, a portion of which is adjusted according to inflation indexes, for an initial term of 15 years, with Electricité de France. The equity's purchase price is approximately €27.2 million (or $39.9 million), subject to certain adjustments. Innergex’s net share of the purchase price will amount to about €16.5 million (or $24.2 million) and will be paid through available funds under its corporate revolving credit facility. Non-recourse debts related to the projects, which are already in place, will amount to €72.0 million (or $105.7 million) and will remain at the project level. The Corporation will reduce its exposure to exchange rate fluctuations by entering into long-term currency hedging instruments. Innergex will have a 69.55% interest in the wind farms and Desjardins Group Pension Plan will own the remaining 30.45%. The acquisition remains subject to customary closing conditions.

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

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

	Notes	Three months ended June 30 2017	Three months ended June 30 2016	Six months ended June 30 2017	Six months ended June 30 2016
Revenues		109,530	87,784	184,056	150,265
Expenses					
Operating	4	17,215	14,218	33,304	23,616
General and administrative		4,757	3,945	9,335	7,632
Prospective projects		1,638	2,758	4,556	4,475
Earnings before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net loss (gain) on financial instruments		85,920	66,863	136,861	114,542
Finance costs	5	39,064	24,608	68,361	44,102
Other net revenues	6	(413)	(233)	(772)	(407)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net loss (gain) on financial instruments		47,269	42,488	69,272	70,847
Depreciation	4, 9	23,707	15,070	45,524	28,853
Amortization	4	8,257	7,065	16,022	12,719
Share of earnings of joint ventures		(1,821)	(475)	(2,537)	(24)
Unrealized net loss (gain) on financial instruments		470	(2,145)	(4,605)	(3,432)
Earnings before income taxes		16,656	22,973	14,868	32,731
Income taxes expenses					
Current		859	845	1,743	1,472
Deferred		1,697	6,451	1,359	8,386
		2,556	7,296	3,102	9,858
Net earnings		14,100	15,677	11,766	22,873
Net earnings (loss) attributable to:					
Owners of the parent		14,567	14,381	17,023	22,713
Non-controlling interests		(467)	1,296	(5,257)	160
		14,100	15,677	11,766	22,873
Weighted average number of common shares outstanding (in 000s)	7	108,431	107,318	108,386	105,657
Basic net earnings per share ($)	7	0.12	0.12	0.13	0.19
Diluted weighted average number of common shares outstanding (in 000s)	7	109,426	108,314	109,362	106,469
Diluted net earnings per share ($)	7	0.12	0.12	0.13	0.19

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

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

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Net earnings	14,100	15,677	11,766	22,873
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:				
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	120	(510)	103	(1,091)
Related deferred tax	(30)	65	(30)	153
Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries	(101)	343	190	1,009
Related deferred tax	94	(76)	18	(164)
Change in fair value of hedging instruments	7,207	(5,972)	6,312	(18,087)
Related deferred tax	(2,006)	1,582	(1,766)	4,787
Share of change in fair value of hedging instruments of joint venture	323	—	323	—
Related deferred tax	(85)	—	(85)	—
Share of non-controlling interests in:				
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	164	(27)	196	(27)
Foreign exchange (loss) on the designated hedges on the investments in self-sustaining foreign subsidiaries	(170)	—	(91)	—
Change in fair value of hedging instruments	965	(421)	939	(1,359)
Related deferred tax	(177)	46	(175)	130
Other comprehensive income (loss)	6,304	(4,970)	5,934	(14,649)
Total comprehensive income	20,404	10,707	17,700	8,224
Other comprehensive income (loss) attributable to:				
Owners of the parent	5,522	(4,568)	5,065	(13,393)
Non-controlling interests	782	(402)	869	(1,256)
	6,304	(4,970)	5,934	(14,649)
Total comprehensive income attributable to:				
Owners of the parent	20,089	9,813	22,088	9,320
Non-controlling interests	315	894	(4,388)	(1,096)
	20,404	10,707	17,700	8,224

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	June 30, 2017	December 31, 2016
Assets			
Current assets			
Cash and cash equivalents		82,811	56,227
Restricted cash and short-term investments		81,837	89,742
Accounts receivable		121,411	98,847
Derivative financial instruments		4,406	1,527
Prepaid and others		7,618	5,886
		298,083	252,229
Non-current assets			
Reserve accounts		49,710	49,489
Property, plant and equipment	9	3,056,240	2,700,007
Intangible assets		627,488	544,865
Investments in joint ventures		10,357	8,758
Derivative financial instruments		9,303	8,117
Deferred tax assets		11,483	11,849
Goodwill		8,269	8,269
Other long-term assets		6,449	20,621
		4,077,382	3,604,204

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	June 30, 2017	December 31, 2016
Liabilities			
Current liabilities			
Dividends payable to shareholders		19,379	18,795
Accounts payable and other payables		89,525	85,850
Income tax payable		2,095	1,292
Derivative financial instruments		21,153	14,541
Current portion of long-term debt	10	131,557	99,397
Current portion of other liabilities		374	495
		264,083	220,370
Non-current liabilities			
Derivative financial instruments		56,867	55,194
Accrual for acquisition of long-term assets		2,178	37,401
Long-term debt	10	2,938,278	2,507,236
Other liabilities		35,912	26,966
Liability portion of convertible debentures		95,537	94,840
Deferred tax liabilities		206,685	176,965
		3,599,540	3,118,972
Shareholders' equity			
Common share capital		95	162,862
Contributed surplus from reduction of capital on common shares		941,873	775,413
Preferred shares		131,069	131,069
Share-based payment		2,247	2,199
Equity portion of convertible debentures		1,877	1,877
Deficit		(622,880)	(601,157)
Accumulated other comprehensive income (loss)		3,322	(1,743)
Equity attributable to owners		457,603	470,520
Non-controlling interests		20,239	14,712
Total shareholders' equity		477,842	485,232
		4,077,382	3,604,204

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
Six months ended June 30, 2017	Number of common shares (In 000s)	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, 2017	108,181	162,862	775,413	131,069	2,199	1,877	(601,157)	(1,743)	470,520	14,712	485,232
Net earnings (loss)							17,023		17,023	(5,257)	11,766
Other items of comprehensive income								5,065	5,065	869	5,934
Total comprehensive income	—	—	—	—	—	—	17,023	5,065	22,088	(4,388)	17,700
Common shares issued through dividend reinvestment plan	262	3,693							3,693		3,693
Reduction of capital on common shares (Note 11)		(166,460)	166,460						—		—
Share-based payment					48				48		48
Distributions to non-controlling interests									—	(1,000)	(1,000)
Investments from non-controlling interests									—	10,915	10,915
Dividends declared on common shares							(35,775)		(35,775)		(35,775)
Dividends declared on preferred shares							(2,971)		(2,971)		(2,971)
Balance June 30, 2017	108,443	95	941,873	131,069	2,247	1,877	(622,880)	3,322	457,603	20,239	477,842

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
Six months ended June 30, 2016	Number of common shares (In 000s)	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	103,938	108,541	775,413	131,069	2,174	1,877	(567,848)	(1,576)	449,650	21,907	471,557
Net earnings							22,713		22,713	160	22,873
Other items of comprehensive loss								(13,393)	(13,393)	(1,256)	(14,649)
Total comprehensive income (loss)	—	—	—	—	—	—	22,713	(13,393)	9,320	(1,096)	8,224
Common shares issued on April 15, 2016: private placement	3,906	50,000							50,000		50,000
Common shares issued through dividend reinvestment plan	128	1,530							1,530		1,530
Share-based payment					41				41		41
Investments from non-controlling interests							5,195		5,195	1,218	6,413
Dividends declared on common shares							(33,917)		(33,917)		(33,917)
Dividends declared on preferred shares							(2,971)		(2,971)		(2,971)
Balance June 30, 2016	107,972	160,071	775,413	131,069	2,215	1,877	(576,828)	(14,969)	478,848	22,029	500,877

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

	Notes	Six months ended June 30 2017	2016
Operating activities			
Net earnings		11,766	22,873
Items not affecting cash:			
Depreciation		45,524	28,853
Amortization		16,022	12,719
Share of earnings of joint ventures		(2,537)	(24)
Unrealized net gain on financial instruments		(4,605)	(3,432)
Inflation compensation interest	5	2,831	2,446
Amortization of financing fees	5	1,629	509
Accretion of long-term debt and convertible debentures	5	768	770
Accretion expenses on other liabilities	5	480	232
Share-based payment		48	41
Deferred income taxes		1,359	8,386
Others		(131)	173
Interest on long-term debt and convertible debentures	5	61,819	39,713
Interest paid		(57,672)	(37,164)
Gain on contingent considerations	6	(872)	—
Distributions received from joint ventures		1,261	1,708
Current income tax expense		1,744	1,472
Net income taxes paid		(1,347)	(1,502)
Effect of exchange rate fluctuations		1,135	(657)
		79,222	77,116
Changes in non-cash operating working capital items	12	(8,577)	(18,181)
		70,645	58,935
Financing activities			
Dividends paid on common shares		(31,498)	(31,221)
Dividends paid on preferred shares		(2,971)	(3,266)
Distributions to non-controlling interests		(1,000)	—
Investments from non-controlling interests		10,913	6,392
Increase of long-term debt		300,866	488,206
Repayment of long-term debt		(163,203)	(381,249)
Payment of deferred financing costs		(613)	(1,998)
Payment of other liabilities		(246)	—
Proceeds from issuance of common shares		—	50,000
		112,248	126,864

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Six months ended June 30	
		2017	2016
	Notes		
Investing activities			
Cash acquired on business acquisitions	3	5,057	11,887
Business acquisitions	3	(112,834)	(102,795)
Decrease of restricted cash and short-term investments		17,639	145,207
Net funds withdrawn from the reserve accounts		55	171
Additions to property, plant and equipment		(65,524)	(204,135)
Reductions of (additions to) other long-term assets		71	(14,626)
Proceeds from disposal of property, plant and equipment		12	—
		(155,524)	(164,291)
Effects of exchange rate changes on cash and cash equivalents		(785)	(38)
Net increase in cash and cash equivalents		26,584	21,470
Cash and cash equivalents, beginning of period		56,227	40,663
Cash and cash equivalents, end of period		82,811	62,133
Cash and cash equivalents is comprised of:			
Cash		81,122	58,008
Short-term investments		1,689	4,125
		82,811	62,133

Additional information is presented in Note 12.

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

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 unaudited condensed consolidated financial statements were approved by the Board of Directors on August 3, 2017.

The Corporation's revenues are variable with each season and 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. As a result, earnings of interim periods should not be considered as indicative of results for an entire year.

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

These condensed consolidated financial statements have been prepared using accounting policies consistent with International Financial Reporting Standards ("IFRS"). The condensed consolidated financial statements are in compliance with IAS-34 Interim Financial Reporting. The same accounting policies and methods of application as described in the Corporation's latest annual report have been used. However, these condensed consolidated financial statements do not include all disclosures required under IFRS and, accordingly, should be read in conjunction with the audited consolidated financial statements and the notes thereto included in the Corporation's latest annual report.

The condensed 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 included in the Corporation's latest annual report.

2. APPLICATION OF IFRS

2.1 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 course in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. They also began reviewing the application of the standard to the Corporation.

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 course 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. 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 is a net cash consideration of €35,184 (all amounts in € are in thousands of €) ($48,983), subject to certain adjustments. A €10,000 ($13,922) deposit had already been provided by the Corporation last year.

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

	Preliminary purchase price allocation	
	€	$
Cash and cash equivalents	3,583	4,989
Accounts receivable	12,936	18,009
Prepaid and others	351	488
Property, plant and equipment	76,629	106,683
Intangible assets	24,138	33,605
Accounts payable and other payables	(712)	(991)
Long-term debt	(72,753)	(101,287)
Derivative financial instruments	(683)	(951)
Asset retirement obligations	(1,855)	(2,582)
Deferred tax liabilities	(6,450)	(8,980)
Net assets acquired	35,184	48,983

The purchase price allocation remains subject to the completion of the valuation of working capital adjustments, property, plant and equipment, intangible assets, deferred tax liabilities 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 6).

If the acquisition had taken place on January 1, 2017, the consolidated revenues and net earnings for the six-month period ended June 30, 2017 would have been $185,517 and $12,382 respectively.

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

The amounts of revenues and net loss of the facilities since February 21, 2017 included in the consolidated statement of earnings are $3,465 and $546 respectively for the 130 days ended June 30, 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 Vaites 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 following table reflects the preliminary allocation of the purchase price to the fair value of the net assets acquired:

	Preliminary purchase price allocation	
	€	$
Cash and cash equivalents	45	68
Restricted cash and short term investments	6,443	9,753
Accounts receivable	4,699	7,113
Prepaid and others	52	79
Property, plant and equipment	165,183	250,037
Intangible assets	39,833	60,295
Accounts payable and other payables	(5,612)	(8,495)
Income tax payable	(252)	(382)
Long-term debt	(138,551)	(209,725)
Derivative financial instruments	(6,645)	(10,059)
Asset retirement obligations	(2,944)	(4,456)
Deferred tax liabilities	(10,871)	(16,455)
Net assets acquired	51,380	77,773

The purchase price allocation remains subject to the completion of the valuation of working capital adjustments, property, plant and equipment, intangible assets, deferred tax liabilities 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 6).

If the acquisition had taken place on January 1, 2017, the consolidated revenues and net earnings for the six-month period ended June 30, 2017 would have been $188,134 and $13,709 respectively.

The amounts of revenues and net loss of the facilities since May 24, 2017 included in the consolidated statement of earnings are $1,524 and $583 respectively for the 37 days ended June 30, 2017.

c. Acquisition of 7 operating wind facilities in France

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

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

4. OPERATING EXPENSES

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Salaries	1,244	983	2,521	2,096
Insurance	928	704	1,805	1,366
Operation and maintenance	7,058	5,828	12,609	9,400
Property taxes and royalties	7,985	6,703	16,369	10,754
	17,215	14,218	33,304	23,616

Depreciation and amortization recorded in the consolidated statements of earnings are mainly related to operating expenses incurred to generate revenues.

5. FINANCE COSTS

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Interest on long-term debt and on convertible debentures	34,840	20,315	61,819	39,713
Inflation compensation interest	1,956	3,339	2,831	2,446
Amortization of financing fees	868	259	1,629	509
Accretion of long-term debt and convertible debentures	568	308	768	770
Accretion expenses on other liabilities	248	136	480	232
Others	584	251	834	432
	39,064	24,608	68,361	44,102

6. OTHER NET REVENUES

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Transaction costs	974	355	1,657	1,266
Realized gain on foreign exchange	(166)	(33)	(232)	(543)
Gain on contingent considerations	(615)	—	(872)	—
Other net revenues	(596)	(538)	(1,314)	(828)
(Gain) Loss on disposal of property, plant and equipment	(10)	173	(11)	173
Recovery of loan impairment	—	(190)	—	(475)
	(413)	(233)	(772)	(407)

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

7. EARNINGS PER SHARE

The net earnings per share is computed as follows:

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Net earnings attributable to owners of the parent	14,567	14,381	17,023	22,713
Dividends declared on preferred shares	(1,485)	(1,485)	(2,971)	(2,971)
Net earnings available to common shareholders	13,082	12,896	14,052	19,742
Weighted average number of common shares (in 000s)	108,431	107,318	108,386	105,657
Basic net earnings per share ($)	0.12	0.12	0.13	0.19
Weighted average number of common shares (in 000s)	108,431	107,318	108,386	105,657
Effect of dilutive elements on common shares (in 000s) (a)	995	996	976	812
Diluted weighted average number of common shares (in 000s)	109,426	108,314	109,362	106,469
Diluted net earnings per share ($)	0.12	0.12	0.13	0.19

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. During the three-month and the six-month periods ended June 30, 2017, 3,331,684 of the 3,457,432 stock options (all of the 3,425,684 for the the three-month and the six-month periods ended June 30, 2016) were dilutive.

During the the three-month and six-month periods ended June 30, 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 periods in 2016).

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

8. DERIVATIVE FINANCIAL INSTRUMENTS

As part of the Yonne and Rougemont 1-2 and Vaite Acquisitions, the Corporation entered into hedge agreements to reduce the Corporation's foreign exchange risk.

Contracts	Maturity	Early termination option	Notional Amounts	
			June 30, 2017	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 1.7150/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	—
			284,146	—

As part of the Yonne and Rougemont 1-2 and Vaite Acquisitions, the wind farms hold hedge agreements to mitigate the risk of fluctuations in the interest rates on their long-term debt. Hedge accounting is applied on these contracts.

Contracts	Maturity	Early termination option	Notional Amounts	
			June 30, 2017	December 31, 2016
Contracts used to hedge the interest rate risk				
Interest rate swap, 0.78%, amortizing, translated at CAD 1.4813/Euro	2031	None	66,066	—
Interest rate swap, 1.302%, amortizing, translated at CAD 1.4813/Euro	2032	None	72,418	—
Interest rate swap, 1.303%, amortizing, translated at CAD 1.4813/Euro	2032	None	43,972	—
Interest rate swap, 1.475%, amortizing, translated at CAD 1.4813/Euro	2032	None	11,038	—
Interest rate swap, 1.277%, amortizing, translated at CAD 1.4813/Euro	2032	None	77,950	—

9. 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	—	3,817	2,144	12	26,504	2,046	34,523
Business acquisitions (Note 3)	40	—	281,854	—	74,827	—	356,721
Transfer of assets upon commissioning	—	453,495	(1,131)	—	(452,364)	—	—
Dispositions	—	—	—	—	—	(84)	(84)
Other changes	—	—	9	—	—	(25)	(16)
Net foreign exchange differences	2	(263)	12,730	—	(1,602)	(7)	10,860
As at June 30, 2017	3,053	2,070,066	1,172,175	124,315	73,424	12,760	3,455,793
Accumulated depreciation							
As at January 1, 2017	—	(194,633)	(123,831)	(27,775)	—	(7,543)	(353,782)
Depreciation	—	(17,850)	(23,703)	(2,979)	(246)	(746)	(45,524)
Dispositions	—	—	—	—	—	84	84
Other changes	—	—	—	—	—	25	25
Net foreign exchange differences	—	104	(453)	—	—	(7)	(356)
As at June 30, 2017	—	(212,379)	(147,987)	(30,754)	(246)	(8,187)	(399,553)
Carrying amount as at June 30, 2017	3,053	1,857,687	1,024,188	93,561	73,178	4,573	3,056,240

All of the property, plant and equipment are given as securities under the respective project financing or for corporate financing.

Additions in the current the period include $5,904 of capitalized financing costs incurred prior to their intended use.

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 facility 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).

10. LONG-TERM DEBT

(references to US$ and € are in thousands)

	Interests rate 2017	Maturity	June 30, 2017
Loans (Non-recourse to the Corporation)			
b) Innergex Champagne S.A.S. (€4,250)	7.25%	2025	6,296
b) Innergex Lorraine S.A.S. (€4,250)	7.25%	2025	6,296
c) Yonne (€14,028)	1.08%	2028	20,780
c) Yonne (€44,600)	1.54%	2031	66,066
d) Rougemont 1 (€1,384)	1.00%	2018	2,050
d) Rougemont 1 (€49,139)	0.81%	2035	72,790
d) Rougemont 2 (€953)	1.00%	2019	1,412
d) Rougemont 2 (€30,505)	0.81%	2035	45,186
d) Rougemont 2 (€10,567)	0.84%	2035	15,654
d) Vaite (€506)	1.00%	2018	750
d) Vaite (€52,386)	0.81%	2035	77,599

a. Revolving credit facility

On February 21, 2017, the Corporation executed a Fifth Amended and Restated Credit Agreement of its existing $425,000 revolving credit facility. 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. Moreover, a Letter of Credit Facility of an amount of up to $15 000 guaranteed by Export Development Canada (EDC) was added and will be put in place.

b. 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.

c. Long-term debt for Yonne in France

As part of the Yonne Acquisition, the Corporation assumed the related loan facilities for a total of €70,587.
- A €11,123 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 €3,809 for the twelve month period following the acquisition. The loan was accounted for at its fair market value of €15,313 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. No principal repayments are set for the twelve month period following the acquisition. The loan was accounted for at its fair market value of €46,055 for an effective rate of 1.54%. As at June 30, 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 €106,136.

d. Long-term debt for Rougemont and Vaites in France

Rougemont 1

As part of the Rougemont 1-2 and Vaite Acquisition, the Corporation assumed the related loan facilities for a total of €51,371.

- A €1,384 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.

- 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 €2,931 for the twelve month period ending June 30, 2018. The loan was accounted for at its fair market value of €49,027 for an effective rate of 0.81%. As at June 30, 2017, the all-in effective interest rate was 2.07% after accounting for the interest swap.
- 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 June 30, 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 June 30, 2017 an amount of €700 has been used to secure letter of credits related to the decommissionning guarantee.The debt is secured by the assets of Énergies du Plateau Central with a carrying value of approximately €61,850.

Rougemont 2

As part of the Rougemont 1-2 and Vaite Acquisition, the Corporation assumed the related loan facilities for a total of €40,735.
- A €753 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.
- 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 €1,605 for the twelve month period ending June 30, 2018. The loan was accounted for at its fair market value of €30,505 for an effective rate of 0.81%. As at June 30, 2017, the all-in effective interest rate was 2.04% after accounting fot the interest swap.
- 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. No principal repayments are due for the twelve month period ending June 30, 2018. The loan was accounted for at its fair market value of €8,430 for an effective rate of 0.84%. As at June 30, 2017, the all-in effective interest rate was 1.71% after accounting for the interest swap.
- 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 June 30, 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 June 30, 2017 an amount of €431 has been used to secure letter of credits related to the decommissionning guarantee.The debt is secured by the assets of Énergies du Plateau Central 2 with a carrying value of approximately €56,699.

Vaite

As part of the Rougemont 1-2 and Vaite Acquisition, the Corporation assumed the related loan facilities for a total of €53,992.
- A €576 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.
- A €53,416 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 €3,257 for the twelve month period ending June 30, 2018. The loan was accounted for at its fair market value of €52,386 for an effective rate of 0.81%. As at June 30, 2017, the all-in effective interest rate was 2.06% after accounting for the interest swap.
- 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 June 30, 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 June 30, 2017 an amount of €754 has been used to secure letter of credits related to the decommissionning guarantee.The debt is secured by the assets of Énergies du Réchet with a carrying value of approximately €63,224.

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

11. SHAREHOLDERS ' CAPITAL

a) 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.

12. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Six months ended June 30	
	2017	2016
Accounts receivable and income tax receivable	3,937	(14,187)
Prepaid and others	(923)	2
Accounts payable and other payables and income tax payable	(11,591)	(3,996)
	(8,577)	(18,181)

b. Additional information

	Six months ended June 30	
	2017	2016
Interest paid (including $5,812 capitalized interest ($20,660 in 2016))	63,484	57,824
Non-cash transactions		
in unpaid property, plant and equipment	(32,484)	(4,318)
in unpaid issuance costs of common shares	—	(95)
in common shares issued through dividend reinvestment plan	(3,693)	(1,531)
loans to partners in exchange of non-controlling interests in subsidiaries	(2)	(21)

c. Changes in liabilities arising from financing activities

	Six months ended June 30	
	2017	2016
Long-term debt at beginning of the period	2,606,633	2,215,433
Increase of long-term debt	300,866	488,206
Repayment of long-term debt	(163,203)	(381,249)
Payment of deferred financing costs	(613)	(1,998)
Business acquisitions (Note 3)	311,012	130,170
Other changes	5,308	3,143
Net foreign exchange differences	9,832	(4,920)
Long-term debt at end of the period	3,069,835	2,448,785

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

13. SUBSIDIARIES

Yonne

An investment of $8,568 including a debenture of $6,478 was made by Régime de rentes du Mouvement Desjardins into Innergex Europe (2015) Limited Partnership to partly finance a portion of the acquisition of Yonne on February 21, 2017.

The summarized financial information below represents amounts before intragroup eliminations.

As at	June 30, 2017
Summary Statement of Financial Position	
Current assets	10,476
Non-current assets	146,743
	157,219
Current liabilities	4,678
Non-current liabilities	130,371
Equity attributable to owners	22,170
	157,219

	Three months ended June 30, 2017	Period of 130 days ended June 30, 2017
Summary Statements of Earnings and Comprehensive Income (Loss)		
Revenues	1,915	3,465
Expenses	2,147	4,011
Net loss	(232)	(546)
Other comprehensive income	382	374
Total comprehensive income (loss)	150	(172)

Rougemont 1-2 and Vaite

An investment of $31,119 including a debenture of $22,296 was made by Régime de rentes du Mouvement Desjardins into Innergex Europe (2015) Limited Partnership to partly finance a portion of the acquisition of Rougemont 1-2 and Vaite on May 24, 2017.

The summarized financial information below represents amounts before intragroup eliminations.

As at	June 30, 2017
Summary Statement of Financial Position	
Current assets	18,111
Non-current assets	305,356
	323,467
Current liabilities	27,242
Non-current liabilities	258,334
Equity attributable to owners	37,891
	323,467

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

	Period of 37 days ended June 30, 2017
Summary Statement of Earnings and Comprehensive income	
Revenues	1,524
Expenses	2,107
Net loss	(583)
Other comprehensive income	800
Total comprehensive income	217

14. SEGMENT INFORMATION

Geographic segments

The Corporation had interests in 30 hydroelectric facilities, seven wind farms and one solar farm in Canada, twelve wind farms in France and one hydroelectric facility in the United States. The Corporation operates in three principal geographical areas, which are detailed below:

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Revenues				
Canada	99,865	83,300	164,354	145,129
Europe	8,845	2,812	18,325	2,812
United States	819	1,673	1,377	2,324
	109,529	87,785	184,056	150,265

As at	June 30, 2017	December 31, 2016
Non-current assets, excluding financial instruments and deferred tax assets		
Canada	2,991,989	3,005,720
Europe	759,586	318,924
United States	6,937	7,365
	3,758,512	3,332,009

Operating segments

The Corporation has four operating segments: (a) hydroelectric generation (b) wind power generation (c) solar power generation and (d) site development.

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

For the three-month period ended June 30, 2017					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	74,177	29,777	5,190	386	109,530
Expenses:					
Operating	10,742	6,117	170	186	17,215
General and administrative	2,744	1,939	33	41	4,757
Prospective projects	—	—	—	1,638	1,638
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net loss on financial instruments	60,691	21,721	4,987	(1,479)	85,920
Finance costs					39,064
Other net revenues					(413)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net loss on financial instruments					47,269
Depreciation					23,707
Amortization					8,257
Share of earnings of joint ventures					(1,821)
Unrealized net loss on financial instruments					470
Earnings before income taxes					16,656

For the three-month period ended June 30, 2016 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	66,744	14,984	6,056	—	87,784
Expenses:					
Operating	10,674	3,343	201	—	14,218
General and administrative	2,032	1,204	40	669	3,945
Prospective projects	—	—	—	2,758	2,758
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net gain on financial instruments	54,038	10,437	5,815	(3,427)	66,863
Finance costs					24,608
Other net revenues					(233)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					42,488
Depreciation					15,070
Amortization					7,065
Share of earnings of joint ventures					(475)
Unrealized net gain on financial instruments					(2,145)
Earnings before income taxes					22,973

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

For the six-month period ended June 30, 2017					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	108,535	66,669	8,466	386	184,056
Expenses:					
Operating	21,481	11,292	345	186	33,304
General and administrative	5,510	3,360	88	377	9,335
Prospective projects	—	—	—	4,556	4,556
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net gain on financial instruments	81,544	52,017	8,033	(4,733)	136,861
Finance costs					68,361
Other net revenues					(772)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					69,272
Depreciation					45,524
Amortization					16,022
Share of earnings of joint ventures					(2,537)
Unrealized net gain on financial instruments					(4,605)
Earnings before income taxes					14,868

As at June 30, 2017					
Goodwill	8,269	—	—	—	8,269
Total assets	2,465,780	1,400,781	105,077	105,744	4,077,382
Total liabilities	2,120,652	1,273,742	110,085	95,061	3,599,540
Acquisition of property, plant and equipment during the period	4,222	284,234	12	102,776	391,244

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

For the six-month period ended June 30, 2016					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	109,184	31,739	9,342	—	150,265
Expenses:					
Operating	17,784	5,473	359	—	23,616
General and administrative	3,984	2,151	80	1,417	7,632
Prospective projects	—	—	—	4,475	4,475
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net gain on financial instruments	87,416	24,115	8,903	(5,892)	114,542
Finance costs					44,102
Other net revenues					(407)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					70,847
Depreciation					28,853
Amortization					12,719
Share of earnings of joint ventures					(24)
Unrealized net gain on financial instruments					(3,432)
Earnings before income taxes					32,731

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)

15. 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 ($)
08/03/2017	09/29/2017	10/16/2017	0.1650	0.2255	0.359375

b. Final agreement to acquire two wind projects in France

On July 5, 2017, the Corporation and Desjardins Group Pension Plan announced that a final agreement had been signed with BayWa r.e. to purchase two wind projects in France with a total aggregate installed capacity of 43 MW. The electricity to be produced will be sold under power purchase agreements at a fixed price, a portion of which is adjusted according to inflation indexes, for an initial term of 15 years, with Electricité de France. The equity's purchase price is approximately €27,200 ($39,900), subject to certain adjustments. Innergex's net share of the purchase price will amount to about €16,500 ($24,200) and will be paid through available funds under its corporate revolving credit facility. Non-recourse debts related to the projects, which are already in place, will amount to €72,000 ($105,700) and will remain at the project level. The Corporation will reduce its exposure to exchange rate fluctuations by entering into long-term currency hedging instruments. Innergex will have a 69.55% interest in the wind farms and Desjardins Group Pension Plan will own the remaining 30.45%. The acquisition remains subject to customary closing conditions.

INFORMATION FOR INVESTORS

Stock Exchange Listing

Common shares of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.
Series A Preferred Shares of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.PR.A.
Series C Preferred Shares of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.PR.C.
Convertible Debentures of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.DB.A.

Rating Agencies

Innergex Renewable Energy Inc. is rated BBB- by S&P.
Series A Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P.
Series C Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P.

Transfer Agent and Registrar

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Telephone: 1 800 564-6253 or 514 982-7555
Email: service@computershare.com

Dividend Reinvestment Plan

Innergex Renewable Energy Inc. implemented a Dividend Reinvestment Plan (DRIP) for its common shareholders, which 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 or contact the DRIP administrator, Computershare Trust Company of Canada.

Independent Auditor

Deloitte LLP

Investor Relations

If you have inquiries, please visit our website or contact:

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