INNERGEX

INNERGEX RENEWABLE ENERGY INC.

QUARTERLY REPORT 2016

FOR THE PERIOD ENDED
SEPTEMBER 30, 2016

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, British Columbia, Idaho, USA, and in France. 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 nine-month period ended September 30, 2016, and reflects all material events up to November 9, 2016, 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 consolidated financial statements and the accompanying notes for the three- and nine-month periods ended September 30, 2016, and with the Corporation's *Financial Review* at December 31, 2015.

The unaudited condensed consolidated financial statements attached to this MD&A and the accompanying notes for the three- and nine-month periods ended September 30, 2016, along with the 2015 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.

HIGHLIGHTS – 2016 CUMULATIVE RESULTS & Q3 2016

- Innergex's cumulative results for the first nine-months of 2016 exceeded long-term projections despite a more modest quarter
  - Production was 106% of the long-term average ("LTA") for the first nine months of 2016 and 90% of the LTA for Q3
  - Revenues increased 15% to $219.5 million for the first nine months and increased 10% to $69.3 million in Q3 compared with 2015
  - Adjusted EBITDA rose 14% to $165.7 million for the 2016 first nine months and increased 5% to $51.2 million in Q3 compared with 2015
- In British Columbia, the 40.6 MW Big Silver Creek hydroelectric facility began commercial operation one month earlier than expected and construction costs were on budget
- Construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities and the Mesgi'g Ugju's'n wind farm is progressing at a good pace

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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 September 30, 2016; (b) they have limited the scope of the Corporation's design of DC&P and ICFR to exclude the controls policies and procedures of Energie Antoigné S.A.S., Energie du Porcien S.A.S, Eoles Beaumont S.A.S., Energie des Cholletz S.A.S., Eoliennes de Longueval S.A.S., Energie Des Valottes S.A.S. et Société d'Exploitation du Parc Éolien du Bois d'Anchat (the "Seven French Entities"); 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 September 30, 2016. The design and evaluation of the operating effectiveness of the DC&P and ICFR for the Seven French Entities will be completed in the 12 months following the date of acquisition. Summary unaudited financial information about the Seven French Entities 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, estimated project costs and expected project financing, 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 French Acquisition, 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; health, safety and environmental risks; uncertainties surrounding the development of new facilities; obtainment of permits; variability of installation performance and related penalties; 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; the ability to secure new power purchase agreements or to renew any power purchase agreement; changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; 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; 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; 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*; foreign exchange fluctuations; foreign market growth and development risks; cybersecurity; sufficiency of insurance coverage limits and exclusions; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; 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, including those of the French Acquisition; 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

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.	Variability of facility performance and related penalties Changes to water and land rental expenses Unexpected maintenance expenditures Changes in the purchase price of electricity upon renewal of a PPA
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
Projected Free Cash Flow The Corporation estimates Free Cash Flow as projected cash flow from operations 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 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. It also adjusts for other elements, which represent cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity, such as adding back transaction costs related to realized acquisitions (which are financed at the time of the acquisition), adding back realized losses or subtracting realized gains on derivative financial instruments used to fix the interest rate on project-level debt or the exchange rate on equipment purchases.	Adjusted EBITDA below expectations caused mainly by the risks and uncertainties mentioned above and by higher prospective project expenses Project 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
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
Expected closing of the Acquisition of the Eighth French Wind Farm under construction The Corporation reasonably expects to complete the acquisition of the Eighth French Wind Farm under construction and it has no indication as of today that the closing conditions will not be satisfied by all parties.	Regulatory and political risks Availability of the Capital Performance of the counterparties

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 Net Earnings (Loss), 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 to "Adjusted Net Earnings (Loss)" are to net earnings (loss) of the Corporation, to which the following elements are added (subtracted): unrealized net gain (loss) on financial instruments; realized (gain) loss on derivative financial instruments; impairment of project development costs; income tax expense (recovery) related to the above items; and the share of unrealized net loss (gain) on derivative financial instruments of joint ventures, net of related tax. Innergex uses derivative financial instruments to hedge its exposure to different 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 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. The Adjusted Net Earnings (Loss) of the Corporation aims at eliminating the impact of the mark-to-market rules on derivatives and the effect of impairment of projects development costs 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 Limited Partnership for the wheeling services to be provided to other facilities owned by the Corporation over the course of their PPA, 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 (Loss) 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 www.sedar.com or on the Corporation's website at www.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

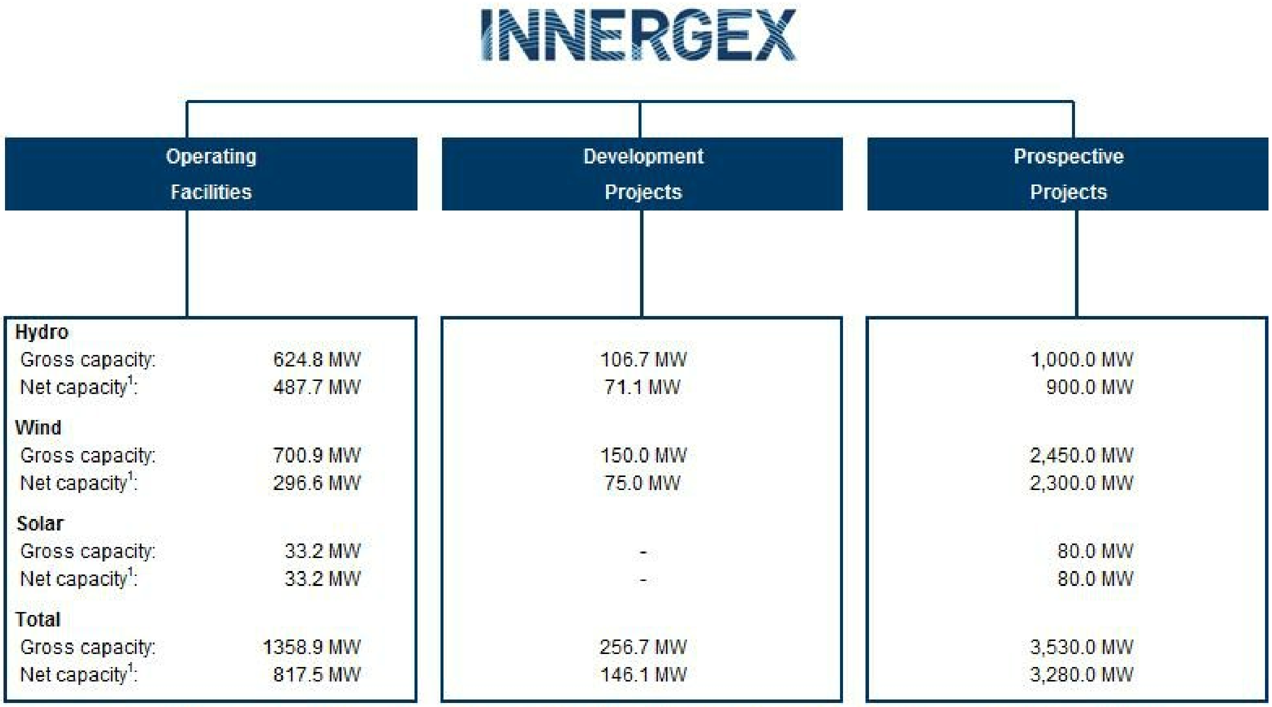
The Corporation is a developer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind power and solar photovoltaic (“PV”) projects that benefit from low operating and management costs and simple, proven technologies.

Portfolio of Assets

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

- 43 facilities in commercial operation (the “Operating Facilities”). Commissioned between 1992 and July 2016, the facilities have a weighted average age of approximately 8.1 years. They sell the generated power under long-term Power Purchase Agreements (“PPA”) that have a weighted average remaining life of 17.9 years (based on gross long-term average production);
- One project scheduled to begin commercial operation by the end of 2016 and two projects scheduled to begin commercial operations in the first and second quarter of 2017 (all together the “Development Projects”). Construction is ongoing at all three of these projects;
- 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 diagrams the Corporation's direct and indirect interests in the Operating Facilities, Development Projects and Prospective Projects.



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

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

BUSINESS STRATEGY

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

Dividend Policy

The Corporation currently distributes an annual dividend of $0.64 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, Adjusted Net Earnings (Loss), Free Cash Flow 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 29 hydroelectric facilities, which draw on 26 watersheds, 13 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	357.9	14%	919.6	35%	789.8	30%	523.4	20%	2,590.7
WIND	269.2	32%	177.0	21%	141.6	17%	258.0	31%	845.9
SOLAR[2]	7.2	19%	12.4	33%	12.5	33%	5.7	15%	37.9
Total	634.3	18%	1,109.0	32%	944.0	27%	787.1	23%	3,474.4

1. The consolidated long-term average production is the annualized LTA for the facilities in operation at November 9, 2016. 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.
2. Solar farm LTA diminishes over time due to expected solar panel degradation.

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

THIRD QUARTER UPDATE

Summary of operating and financial performance

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
PRODUCTION				
Power generated (MWh)	831,840	777,975	2,672,678	2,340,575
LTA (MWh)	924,439	849,747	2,526,725	2,363,711
Production as percentage of LTA	90%	92%	106%	99%
STATEMENT OF EARNINGS				
Revenues	69,255	62,680	219,520	190,578
Adjusted EBITDA	51,176	48,550	165,720	144,920
Adjusted EBITDA Margin	73.9%	77.5%	75.5%	76.0%
Net earnings (loss)	409	1,316	23,282	(13,988)
DIVIDENDS				
Dividend declared per Class A Preferred Share	0.2255	0.3125	0.6765	0.9375
Dividend declared per Class C Preferred Share	0.359375	0.359375	1.078125	1.078125
Dividend declared per common share	0.160	0.155	0.480	0.465

For the three-month period ended September 30, 2016, production was 90% of the LTA, due mainly to below-average results in the hydroelectric sector. Production increased 7%, revenues increased 10% and Adjusted EBITDA increased 5% compared with the same period last year. These increases are attributable mainly to better performance at most of the British Columbia ("BC") hydroelectric facilities, in contrast to an exceptionally low production in the same period last year, and to the contribution of the recently commissioned or acquired facilities (namely, the BC Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016, the Seven French Entities acquired in April 2016 and the BC Big Silver Creek facility commissioned in July 2016), which were partly offset by lower production from the hydrologic and wind regimes in Quebec and from the hydrologic regime in Ontario.

For the nine-month period ended September 30, 2016, production was 106% of the LTA, due mainly to above-average results from all regimes except the hydrologic regime in Ontario and the wind regime in France. Production increased 14%, revenues increased 15% and Adjusted EBITDA increased 14% compared with the same period last year. These increases are attributable mainly to the better performance of most of the BC hydroelectric facilities and to the contribution of the aforementioned facilities recently commissioned or acquired by the Corporation, which were partly offset by lower production from the wind regime in Quebec and from the hydro regime in Ontario.

The Corporation realized $0.4 million in net earnings for the three-month period ended September 30, 2016, compared with $1.3 million net earnings for the same period last year. The $0.9 million decrease in net earnings is explained mainly by the increased expenses related mainly to the recently commissioned or acquired facilities and the increase in prospective expenses, which were partly offset by the $6.6 million increase in revenues, the lower net loss on Derivatives and the lower income tax expense. As specifically regards the impact of the Derivatives, in the same period last year, the Corporation recognized a $27.0 million realized loss on Derivatives, which was partly offset by a $24.3 million unrealized net gain on derivative financial instruments, compared with no realized net gain and a $1.3 million unrealized net loss on Derivatives in the present quarter.

The Corporation realized $23.3 million in net earnings for the nine-month period ended September 30, 2016, compared with a $14.0 million net loss for the same period last year. The $37.3 million increase in net earnings can be explained mainly by the $28.9 million increase in revenues and the lower net loss on Derivatives, which were partly offset by the increase in expenses due largely to the recently commissioned or acquired facilities, the $2.5 million increase in prospective expenses and to the $11.1 million increase in the income tax expense. As specifically regards the impact of the Derivatives in the same period last year, the Corporation recognized a $119.6 million realized loss on derivatives, which was partly offset by a $79.4 million unrealized net gain on derivative financial instruments, compared with a $2.1 million unrealized net gain on Derivatives in the present nine-month period.

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

Adjusted Net Earnings (Loss)

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

Impact on net earnings (loss) of Derivatives	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Net earnings (loss)	409	1,316	23,282	(13,988)
Add (Subtract):				
Unrealized net loss (gain) on financial instruments	1,312	(24,325)	(2,120)	(79,406)
Realized loss on derivative financial instruments	—	26,984	—	119,557
(Recovery) income tax expense related to above items	(451)	(321)	748	(9,820)
Share of unrealized net loss on financial instruments of joint ventures, net of related income tax	61	293	765	1,189
Adjusted Net earnings	1,331	3,947	22,675	17,532

Excluding the gains and losses on Derivatives and the related income taxes, the net earnings for the three-month period ended September 30, 2016, would have been $1.3 million, compared with net earnings of $3.9 million for the same period last year. The decrease in net earnings during the three-month period is explained mainly by the increased expenses related mainly to the recently commissioned or acquired facilities and the increase in prospective expenses, which was partly offset by the $6.6 million increase in revenues.

Excluding the gains and losses on Derivatives and the related income taxes, the net earnings for the nine-month period ended September 30, 2016, would have been $22.7 million, compared with net earnings of $17.5 million in 2015, again due mainly to the $28.9 million increase in revenues, which was partly offset by the increase in the operating expenses, finance costs, depreciation and amortization related mainly to the recently commissioned or acquired facilities and the increase in prospective expenses.

Payout Ratio

	Trailing 12 months ended September 30	
	2016	2015
Free Cash Flow[1]	75,847	84,217
Payout Ratio[1]	89%	74%

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 September 30, 2016, the dividends on common shares declared by the Corporation corresponded to 89% of Free Cash Flow, compared with 74% for the corresponding prior twelve-month period. This negative change is due mainly to the decrease in Free Cash Flow and to the higher number of common shares outstanding by virtue of the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex, to the issuance of 94,000 shares following the exercise of stock options as well as to the DRIP, partly offset by the purchase and cancellation of 483,876 shares under the Corporation's normal course issuer bid.

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

DEVELOPMENT PROJECTS & COMMISSIONING ACTIVITIES

On July 29, 2016, the Big Silver Creek hydroelectric facility began commercial operation In British Columbia.

Commissioning activities

	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project costs		Expected year-one	
					Estimated[1] ($M)	As at Sept. 30 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
HYDRO (British Columbia)								
Big Silver Creek	100.0	40.6	139.8	40	206.0	206.1	17.2	14.5

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

Big Silver Creek

In the third quarter, the Corporation began commercial operation of the 40.6 MW Big Silver Creek run-of-river hydroelectric facility located in British Columbia. The Big Silver Creek facility is located on crown land approximately 40 km north of Harrison Hot Springs, British Columbia. Construction began in June 2014 and was completed in July 2016, earlier than expected and on budget. The Commercial Operation Date ("COD") certificate has been approved by BC Hydro with an effective commissioning date of July 29, 2016. Big Silver Creek's average annual production is estimated to reach 139,800 MWh, enough to power more than 12,700 households.

In its first full year of operation, it is expected to generate revenues and Adjusted EBITDA of circa $17.2 million and $14.5 million respectively. The small decrease in expected revenues and Adjusted EBITDA compared to prior information is due to lower inflation encountered in the last few years. All the electricity it 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 which provides for an annual adjustment to the selling price based on a portion of the Consumer Price Index. On June 22, 2015, the Corporation announced the closing of a $197.2 million non-recourse construction and term project financing for this project.

Construction activities

Earlier in 2016, the Corporation significantly increased the gross estimated LTA for Mesgi'g Ugju's'n, which resulted in a $4.6 million increase in expected revenues and a $4.5 million increase in Adjusted EBITDA, as explained in greater detail below. At the end of 2015, the Corporation reviewed the total project costs anticipated to achieve the completion of the Development Projects.

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

As at September 30, 2016, the Corporation anticipated no further changes in the total project costs. Accordingly, the total project costs for the Development Projects were as follows:

PROJECTS UNDER CONSTRUCTION	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1, 2] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[1] ($M)	As at Sept. 30 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
HYDRO (British Columbia)									
Upper Lillooet River	66.7	81.4	2017 [4]	334.0	40	327.1 [3]	301.0 [3]	33.0 [3]	27.5 [3]
Boulder Creek	66.7	25.3	2017 [4]	92.5	40	124.1 [3]	105.3 [3]	9.0 [3]	7.5 [3]
WIND (Quebec)									
Mesgi'g Ugju's'n	50.0	150.0	2016	562.5	20	305.0 [3]	255.9 [3]	59.6 [3]	52.5 [3]
		256.7		989.0		756.2	662.2	101.6	87.5

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. Upon commissioning, LTA figures may be updated to reflect design optimization or constraints or selection of different turbines. Please refer to the "Forward-Looking Information" section for more information.
3. Corresponding to 100% of this facility.
4. The COD should be reached in the first quarter of 2017 for the Upper Lillooet hydroelectric project and in the second quarter of 2017 for the Boulder Creek hydroelectric facility. Commercial operation has been delayed due to the forest fire that forced the interruption of construction activities in the summer 2015. BC Hydro has agreed that the fire constitutes a force majeure event and consequently confirmed that the COD could be delayed up to 98 force majeure days. If financial consequences nonetheless result from the fire, the Upper Lillooet River and Boulder Creek projects expect to be indemnified for such delays by virtue of their insurance coverage.

Upper Lillooet River and Boulder Creek

The construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities began in October 2013. On March 17, 2015, the Corporation announced the closing of a $491.6 million non-recourse construction and term project financing for both these projects, which has received the Clean Energy BC's Finance Award for 2015 and the 2016 Hydro Power Deal of the Year from the World Finance Magazine.

As at the date of this MD&A, the Upper Lillooet tunnel invert, final lining and rock trap are now complete. The hydro-mechanical progress on the intake was delayed due to landslide hazard shutdowns and is now expected to be completed in November. The powerhouse turbine and generation equipment installation is nearly complete with only the auxiliary equipment and controls remaining. The transformer and switchyard are nearly complete. The Upper Lillooet Leave to Commence Diversion ("LTCD") application is under review by the agencies concerned and approval is expected by mid-November.

The Boulder Creek tunnel excavation was completed at the end of August and invert cleaning and final support works are well under way. The steel liner work is scheduled to commence in mid-November. The intake civil and hydro-mechanical work is complete with only the electrical work and controls remaining. The LTCD package has been submitted to the agencies concerned for approval.

The joint transmission line is nearly completed and will be commissioned by mid-November.

The insurance claims process for the fire continues with interim progress payments being made. The insurer has hired a consultant to review the project schedules and progress. In any case, the Corporation expects to be indemnified and to suffer no significant adverse financial consequences from the forest fire.

Mesgi'g Ugju's'n

Construction of this wind farm began in May 2015. On September 28, 2015, the Corporation and its partner, the three Mi'gmaq communities of Quebec, announced the closing of a $311.7 million non-recourse construction and term project financing for this project.

As at the date of this MD&A, all access roads, crane pads, wind turbines generator ("WTG") foundations and electrical collector system have been completed. All wind turbines have been delivered and all major turbine components erected. Turbine electrical and mechanical completion work and commissioning of the wind turbines is ongoing. The twin transformer electrical interconnection station has been completed and energized. The Corporation expects the project to reach commercial operation, on budget, by the end of 2016.

As reported in the previous quarter's MD&A, the Corporation has revised the annual forecast for the Gross estimated LTA energy yield upward from 515 GWh to 562.5 GWh, which corresponds approximately to a 9% increase. The revised Gross estimated LTA of the Mesgi'g Ugju's'n wind farm will result in a $3.2 million increase in Projected Free Cash Flow allocated to Innergex. Innergex is entitled to approximately 70% of the total free cash flows that will be generated by the project for the year 2017.

PROSPECTIVE PROJECTS

With a combined potential net installed capacity of 3,280 MW (gross 3,530 MW), all the Prospective Projects are in the preliminary development stage.

Some Prospective Projects are targeted toward specific future requests for proposals, such as the current request for expressions of interest from Aboriginal businesses for a total of up to 40 MW of renewable generation from multiple projects in the province of New Brunswick. Also, the government of Saskatchewan plans to launch an initial Request For Proposals for 100-200 MW of new wind energy in early 2017. In September 2016, the Alberta Government announced it was targeting for 30% of all electricity used in Alberta to come from renewable sources, including wind, hydro and solar, by 2030. To reach the target, the province intends to support 5,000 MW of additional renewable capacity. In Ontario, the government has, for the time being, cancelled the second phase of the competitive Large Renewable Procurement process.

Other Prospective Projects in other jurisdictions will be available for future, yet-unannounced requests for proposals or are targeted toward negotiated power purchase agreements with public utilities or other creditworthy counterparties. There is no certainty that any Prospective Project will be realized.

OPERATING RESULTS

Electricity production in the last quarter was 90% of the LTA production due mainly to below-average results in the hydroelectric sector in British Columbia.

During the quarter, production increased 7%, revenues increased 10% and Adjusted EBITDA increased 5%. These increases are attributable mainly to better performance at most of the BC hydroelectric facilities compared with last year quarter and to the contribution of the recently commissioned or acquired facilities and were partly offset by lower production from the hydrologic and wind regimes in Quebec and from the hydrologic regime in Ontario.

The Corporation's operating results for the three- and nine-month periods ended September 30, 2016, are compared with the operating results for the same period in 2015.

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.

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

Three months ended September 30	2016				2015			
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]
HYDRO								
Quebec	176,674	180,225	98%	71.06	205,081	180,225	114%	67.82
Ontario	3,028	8,233	37%	64.22	10,354	8,233	126%	65.53
British Columbia	478,033	565,124	85%	76.47	400,651	519,156	77%	75.74
United States	15,215	16,694	91%	108.37	14,481	16,694	87%	110.37
Subtotal	672,950	770,275	87%	75.72	630,567	724,308	87%	73.79
WIND								
Quebec	125,638	112,805	111%	80.03	134,377	112,803	119%	79.45
France	19,333	28,814	67%	124.16	—	—	—%	—
Subtotal	144,970	141,619	102%	85.91	134,377	112,803	119%	79.45
SOLAR								
Ontario	13,920	12,545	111%	420.00	13,031	12,636	103%	420.00
Total	831,840	924,439	90%	83.25	777,975	849,747	92%	80.57

1. The Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for the sake of consistency, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the Investments in Joint Ventures section.
2. Including all payment adjustments related to the month, day and hour of delivery, to environmental attributes and to the ecoENERGY Initiative, as applicable.

During the three-month period ended September 30, 2016, the Corporation's facilities produced 832 GWh of electricity or 90% of the LTA of 924 GWh. Overall, the hydroelectric facilities produced 87% of their LTA due to below-average water flows in all markets. Overall, the wind farms produced 102% of their LTA due to the above-average wind regime in Quebec, partly offset by the below-average wind regime in France. The Stardale solar farm produced 111% 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 7% production increase over the same period last year is due mainly to production that was above last year's levels at most of the BC hydroelectric facilities during the quarter and, to a lesser extent, to the contribution of the recently commissioned or acquired facilities, namely the BC Tretheway Creek hydro facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016, the Seven French Entities acquired in April 2016 and the BC Big Silver Creek hydro facility commissioned in July 2016, which were partly offset by lower production from the hydro and wind regimes in Quebec and the hydro regime in Ontario.

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

Nine months ended September 30	2016				2015			
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]
HYDRO								
Quebec	527,761	518,444	102%	79.44	545,285	518,445	105%	74.17
Ontario	40,091	53,332	75%	65.41	49,771	53,332	93%	67.33
British Columbia	1,496,882	1,355,657	110%	74.56	1,152,409	1,248,760	92%	76.16
United States	44,113	41,577	106%	90.07	40,374	41,577	97%	89.43
Subtotal	2,108,847	1,969,010	107%	75.94	1,787,839	1,862,114	96%	75.60
WIND								
Quebec	486,054	469,215	104%	80.20	519,515	469,213	111%	79.80
France	41,616	56,349	74%	125.25	—	—	—%	—
Subtotal	527,670	525,564	100%	83.75	519,515	469,213	111%	79.80
SOLAR								
Ontario	36,161	32,151	112%	420.00	33,221	32,384	103%	420.00
Total	2,672,678	2,526,725	106%	82.13	2,340,575	2,363,711	99%	81.42

1. The Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for the sake of consistency, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the Investments in Joint Ventures section.
2. Including all payment adjustments related to the month, day and hour of delivery, to environmental attributes and to the ecoENERGY Initiative, as applicable.

During the nine-month period ended September 30, 2016, the Corporation's facilities produced 2,673 GWh of electricity or 106% of the LTA of 2,527 GWh. Overall, the hydroelectric facilities produced 107% of their LTA due mainly to above-average water flows in all markets but Ontario. Overall, the wind farms produced 100% of their LTA due to the above-average wind regime in Quebec and below-average wind regime in France. The Stardale solar farm produced 112% 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 14% production increase over the same period last year is due mainly to higher water flows in BC, partly offset by lower water flows in Quebec and Ontario and the lower wind regime in Quebec.

The overall performance of the Corporation's facilities for the period ended September 30, 2016, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind and solar power generation.

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

Financial Results

	Three months ended September 30				Nine months ended September 30			
	2016		2015		2016		2015	
Revenues	69,255	100.0%	62,680	100.0%	219,520	100.0%	190,578	100.0%
Operating expenses	12,170	17.6%	9,406	15.0%	35,785	16.3%	29,753	15.6%
General and administrative expenses	2,915	4.2%	2,992	4.8%	10,546	4.8%	10,890	5.7%
Prospective project expenses	2,994	4.3%	1,732	2.8%	7,469	3.4%	5,015	2.6%
Adjusted EBITDA	51,176	73.9%	48,550	77.5%	165,720	75.5%	144,920	76.0%
Finance costs	24,923		22,075		69,025		63,032	
Other net (revenues) expenses	(224)		27,200		(631)		119,679	
Depreciation and amortization	23,116		18,793		64,688		56,371	
Share of loss (earnings) of joint ventures (note 1)	416		352		393		(704)	
Unrealized net loss (gain) on financial instruments	1,312		(24,325)		(2,120)		(79,406)	
Income tax expense (recovery of)	1,224		3,139		11,083		(64)	
Net earnings (loss)	409		1,316		23,282		(13,988)	
Net earnings (loss) attributable to:								
Owners of the parent	3,419		5,804		26,132		(532)	
Non-controlling interests	(3,010)		(4,488)		(2,850)		(13,456)	
	409		1,316		23,282		(13,988)	
Basic net earnings (loss) per share ($)	0.02		0.04		0.20		(0.06)	

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 September 30, 2016, the Corporation recorded revenues of $69.3 million, compared with $62.7 million for the three-month period ended September 30, 2015. This 10% increase is attributable mainly to better results from most of the British Columbia hydroelectric facilities compared with the same period last year and to the contribution of the recently commissioned or acquired facilities (the BC Tretheway Creek hydro facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016, the French Acquisition made in April 2016 and the BC Big Silver Creek facility commissioned this quarter), which were partly offset by lower revenues from the hydro and wind regime in Quebec and the hydrologic regime in Ontario. The higher rate of increase for revenues than for production is explained by the fact that some production is sold at a higher price.

For the nine-month period ended September 30, 2016, the Corporation recorded revenues of $219.5 million, compared with $190.6 million for the nine-month period ended September 30, 2015. This 15% increase is attributable mainly to better results in all hydroelectricity markets except Ontario and to the contribution of the recently commissioned or acquired facilities, which were partly offset by lower revenues from the wind regime in Quebec.

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 nine-month periods ended September 30, 2016, the Corporation recorded operating expenses of $12.2 million and $35.8 million respectively ($9.4 million and $29.8 million respectively in 2015). This increase of 29% for the quarter and 20% for the nine-month period is due mainly to the production levels and repairs and maintenance in British Columbia as well as the addition of the Tretheway Creek hydro facility, the BC Walden North hydroelectric facility, the French Acquisition and the BC Big Silver Creek facility and the variable costs associated with it.

General and administrative expenses consist primarily of salaries, professional fees and office expenses. For the three- and nine-month periods ended September 30, 2016, general and administrative expenses totalled $2.9 million and $10.5 million respectively ($3.0 million and $10.9 million respectively in 2015). The 3% decrease for the quarter and for the nine-month period stems mainly from resources being devoted to further pursuing the development of international markets and acquisitions, which are accounted for in the prospective project expenses and transaction costs.

Prospective project expenses include the costs incurred for the development of Prospective Projects. They result from the number of Prospective Projects that the Corporation chooses to advance and the resources required to do so. For the three- and nine-month periods ended September 30, 2016, prospective project expenses totalled $3.0 million and $7.5 million respectively ($1.7 million and $5.0 million respectively in 2015). This increase of 73% for the quarter and 49% for the nine-month period is related mainly to the advancement of a number of prospective projects, to pursuing opportunities in new international markets and to current and future requests for proposals and expressions of interest in the Canadian provinces.

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 nine-month periods ended September 30, 2016, the Corporation recorded Adjusted EBITDA of $51.2 million and $165.7 million, compared with $48.6 million and $144.9 million for the same period last year. This increase of 5% for the quarter and 14% for the nine-month period is due mainly to the increase in production and revenues, partly offset by higher operating expenses and prospective project expenses. The adjusted EBITDA Margin decreased from 77.5% to 73.9% for the quarter and from 76.0% to 75.5% for the nine-month period due mainly to the increase in operating expenses and to more resources being devoted to prospective project expenses.

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 September 30, 2016, finance costs totalled $24.9 million ($22.1 million in 2015). The increase is due mainly to the rise in interest expenses on long-term debt following the commissioning of the BC Tretheway Creek and BC Big Silver Creek hydroelectric facilities and the French Acquisition, partly offset by lower inflation compensation interest on the real-return bonds attributable to lower inflation during the period.

For the nine-month period ended September 30, 2016, finance costs totalled $69.0 million ($63.0 million in 2015). The increase is due mainly to expenses related to the recently commissioned or acquired facilities (the BC Tretheway Creek and Big Silver Creek hydroelectric projects commissioned respectively in November 2015 and July 2016 and the French Acquisition) and to higher inflation compensation interest on the real-return bonds attributable to higher inflation during the period.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 4.93% as at September 30, 2016 (5.17% as at September 30, 2015).

Other Net (Revenues) Expenses

Other net (revenues) expenses include transaction costs, realized loss on derivative financial instruments, realized (gain) loss on foreign exchange, other net revenues and recovery of loan impairment. The Corporation recorded, for the three- and nine-month periods ended September 30, 2016, other net revenues of $0.2 million and $0.6 million (net expenses of $27.2 million and $119.6 million respectively in 2015). The significant decrease in other net expenses for the quarter and for the nine-month period stems mainly from the fact that the Corporation had no realized gains, compared with a realized loss of $27.0 million and $119.6 million respectively for the same periods last year upon settlement of the Big Silver Creek, Boulder Creek, Upper Lillooet and Mesgi'g Ugju's'n bond forward contracts at the closing of the projects' financing.

Depreciation and Amortization

For the three- and nine-month periods ended September 30, 2016, depreciation and amortization expenses totalled $23.1 million and $64.7 million respectively ($18.8 million and $56.4 million respectively in 2015). This increase is attributable mainly to the Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016, the French Acquisition made in April 2016 and the BC Big Silver Creek hydroelectric facility commissioned this quarter.

Share of Loss (Earnings) of Joint Ventures

For each of the three- and nine-month periods ended September 30, 2016, the Corporation recorded a share of net loss of joint ventures of $0.4 million (a share of net loss of $0.4 million and of net earnings of $0.7 million respectively in 2015). 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.

Since October 2014, the Corporation has, whenever possible, used hedge accounting for new Derivatives and, since April 1, 2015, it has used hedge accounting for its existing Derivatives used to fix the interest rate on the project-level debts (with the exception of Umbata Falls) and on most of its revolving term credit facility in order to reduce the fluctuations in net earnings or losses resulting from unrealized gains or losses on these Derivatives during a given period. Under hedge accounting, most of the unrealized gains or losses on Derivatives that arise from a decrease or increase in the benchmark interest rate are recorded in other comprehensive income, while only the portion of the unrealized gain or loss related to the "ineffectiveness" and the settlement of the Derivatives will be recorded in net earnings (loss).

For the three-month period ended September 30, 2016, the Corporation recognized a $1.3 million unrealized net loss on financial instruments, due mainly to a loss recorded on the foreign exchange rate swap following an unfavorable change in CAD-EUR foreign exchange rate, which was partly offset by an unrealized net gain on interest rate swaps.

For the nine-month period ended September 30, 2016, the Corporation recognized a $2.1 million unrealized net gain on financial instruments, due mainly to a gain on the interest rate swaps, which was partly offset by an unrealized net loss on the foreign exchange rate swap due mainly to an unfavorable change in CAD-EUR foreign exchange rate.

For the three- and nine-month periods ended September 30, 2015, the Corporation recognized an unrealized net gain on Derivatives of $24.3 million and $79.4 million respectively, due mainly to the reversal of the unrealized loss accrued upon settlement of the bond forward contracts concurrently with the closing of the Boulder Creek and Upper Lillooet River project financing in March, the Big Silver Creek project financing in June and the Mesgi'g Ugju's'n project financing in September.

For the period ended September 30, 2016, the Corporation had no Derivatives to be settled upon the closing of a project financing, as all the Development Project financings were put in place in 2015.

Income Tax Expense (Recovery)

For the three-month period ended September 30, 2016, the Corporation recorded a current income tax expense of $1.0 million ($0.8 million in 2015) and a deferred income tax expense of $0.2 million (deferred income tax expense of $2.3 million in 2015). The lower deferred income tax expense in this quarter is due mainly to the lower earnings before income taxes. The recognition of a deferred, rather than current, income tax expense in 2015 was due mainly to the existence of accumulated tax losses.

For the nine-month period ended September 30, 2016, the Corporation recorded a current income tax expense of $2.5 million ($2.5 million in 2015) and a deferred income tax expense of $8.6 million (deferred income tax recovery of $2.5 million in 2015). The deferred income tax expense is due primarily to the recognition of accounting earnings before income taxes resulting from the Corporation's regular business activities. The deferred income tax recovery for the same period last year was due mainly to a $119.6 million realized loss on derivative financial instruments resulting from the settlement of the Boulder Creek, Upper Lillooet River, Big Silver Creek and Mesgi'g Ugju's'n bond forward contracts upon closing of the financing for these projects, partly offset by a $79.4 million unrealized net gain on Derivatives resulting from the reversal of the unrealized loss accrued upon settlement of Derivatives.

Net Earnings (Loss)

Net earnings of $0.4 million (basic and diluted net earnings of $0.02 per share), compared with net earnings of $1.3 million (basic and diluted net earnings of $0.04 per share), were recorded by the Corporation in the quarter. The $0.9 million decrease in net earnings is explained mainly by the increased expenses arising mainly from the recently commissioned or acquired facilities and the increase in prospective expenses, which were partly offset by the $6.6 million increase in revenues, the lower net loss on Derivatives and the lower income tax expense. As specifically regards the impact of the Derivatives, the Corporation recognized a $27.0 million realized loss on derivatives in the same period last year, which was partly offset by a $24.3 million unrealized net gain on financial instruments, compared with no realized net gain and a $1.3 million unrealized net loss on Derivatives in the present quarter.

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

For the nine-month period ended September 30, 2016, the Corporation recorded net earnings of $23.3 million (basic and diluted net earnings of $0.20 per share), compared with a net loss of $14.0 million (basic and fully diluted net loss of $0.06 per share) in 2015. The $37.3 million increase in net earnings can be explained mainly by the $28.9 million increase in revenues and the lower net loss on Derivatives, which were partly offset by the increase in expenses due mainly to the recently commissioned or acquired facilities, the $2.5 million increase in prospective expenses and the $11.1 million increase in the income tax expense. As specifically regards the impact of the Derivatives, the Corporation recognized a $119.6 million realized loss on derivatives in the same period last year, which was partly offset by a $79.4 million unrealized net gain on derivative financial instruments, compared with a $2.1 million unrealized net gain on Derivatives in the present nine-month period.

Main items explaining the change in net earnings for the three-month period ended September 30, 2016, compared with the net earnings for the corresponding period in 2015

Main items – Positive impact	Change	Explanation
Adjusted EBITDA	2,626	The Adjusted EBITDA increased in the quarter due mainly to the increase in production and revenues, partly offset by higher operating expenses and prospective project expenses.
Other net (revenues) expenses	27,424	Due mainly to there being no realized gain during the quarter on its derivative financial instruments, compared with a $24.3 million realized loss for the same period last year upon settlement of the Mesgi'g Ugju's'n project bond forward contracts at the closing of its financing.
Main items – Negative impact	**Change**	**Explanation**
Finance costs	2,848	Due mainly to expenses related to the recently commissioned or acquired facilities and to lower inflation compensation interest on the real-return bonds attributable to lower inflation during the period.
Depreciation and amortization	4,323	Due mainly to the Tretheway Creek hydroelectric facility commissioned in November 2015, the French Acquisition made in April 2016 and the BC Big Silver Creek hydroelectric facility commissioned this quarter.
Unrealized net loss (gain) on financial instruments	25,637	Due mainly to hedge accounting on almost all the Corporation's financial instruments, the impact of the unrealized net loss on financial instruments is smaller this quarter. The Corporation recognized a $1.3 million unrealized net loss on Derivatives, due mainly to a loss recorded following an increase in the foreign exchange rates on the Corporation's hedge agreements to reduce foreign exchange risk, which was partly offset by an unrealized net gain on interest rate swaps following the use of hedge accounting.

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

Main items explaining the change in net earnings for the nine-month period ended September 30, 2016, compared with the net loss for the corresponding period in 2015		
Main items – Positive impact	Change	Explanation
Adjusted EBITDA	20,800	Due mainly to the increase in production and revenues, partly offset by operating expenses and prospective project expenses.
Other net (revenues) expenses	120,310	Due mainly to there being no realized gain during the quarter on its Derivatives, compared to a $119.6 million realized loss for the same period last year upon the settlement of the Big Silver Creek, Boulder Creek, Upper Lillooet and Mesgi'g Ugju's'n bond forward contracts at the closing of financings.
Main items – Negative impact	Change	Explanation
Finance costs	5,993	Due mainly to expenses related to the recently commissioned or acquired facilities and to higher inflation compensation interest on the real-return bonds attributable to higher inflation during the period.
Depreciation and amortization	8,317	Due mainly to the Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016, the French Acquisition made in April 2016 and the BC Big Silver Creek hydroelectric facility commissioned this quarter.
Unrealized net loss (gain) on financial instruments	77,286	Due mainly to hedge accounting on almost all the Corporation's financial instruments, the impact of the unrealized net gain on financial instruments is smaller for the first nine months of the year. The Corporation recognized a $2.1 million unrealized net gain, due mainly to the increase in benchmark interest rates since December 31, 2015. For the corresponding period last year, the Corporation recognized a $79.4 million unrealized net gain on Derivatives, due mainly to the reversal of the unrealized loss accrued to December 31, 2014, upon settlement of the bond forward contracts concurrently with the closing of the Boulder Creek, Upper Lillooet, Big Silver Creek and Mesgi'g Ugju's'n financings, which more than offset the unrealized losses on derivative financial instruments resulting from the decrease in benchmark interest rates during the corresponding period in 2015.
Deferred income tax expense	11,105	Due primarily to the recognition of accounting earnings before income taxes resulting from the Corporation's regular business activities. The deferred income tax recovery for the same period last year was due mainly to a $119.6 million realized loss on derivative financial instruments resulting from the settlement of the Boulder Creek, Upper Lillooet River, Big Silver Creek and and Mesgi'g Ugju's'n bond forward contracts upon closing of the financing for these projects, partly offset by a $79.4 million unrealized net gain on Derivatives resulting from the reversal of the unrealized loss accrued upon settlement of Derivatives.

Non-controlling Interests

Non-controlling interests are related to the six hydroelectric facilities of the Harrison Hydro Limited Partnership, the Creek Power Inc. subsidiaries, the Kwoiek Creek Resources Limited Partnership, the Mesgi'g Ugju's'n (MU) Wind Farm, L.P., the Magpie Limited Partnership, the Innergex Sainte-Marguerite S.E.C. entity, the Innergex Europe (2015) Limited Partnership, the Cayoose Creek Power Limited Partnership and their respective general partners. For the three- and nine-month periods ended September 30, 2016, the Corporation allocated losses of $3.0 million and $2.9 million respectively to non-controlling interests (losses of $4.5 million and $13.5 million respectively in 2015). Please refer to the Non-Wholly Owned Subsidiaries section for more information.

Number of Common Shares Outstanding

Weighted average number of common shares outstanding (000s)	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Weighted average number of common shares	108,021	102,975	106,451	101,712
Effect of dilutive elements on common shares[1]	1,070	192	866	302
Diluted weighted average number of common shares	109,091	103,167	107,317	102,014

1. During the three-month period ended September 30, 2016, all of the 3,457,432 stock options (1,785,684 of the 3,425,684 for the three-month period ended September 30, 2015) were dilutive. During the nine-month period ended September 30, 2016, 3,331,684 of the 3,457,432 stock options (all of the 3,425,684 for the nine-month period ended September 30, 2015) were dilutive. During the three-month and nine month periods ended September 30, 2016, 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 2015).

The Corporation's Equity Securities

As at	November 9, 2016	September 30, 2016	September 30, 2015
Number of common shares	108,181,592	108,116,175	104,350,670
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 September 30, 2016, the increase in the number of common shares of the Corporation is attributable to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at September 30, 2016, the increase in the number of common shares since September 30, 2015, is attributable mainly to the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex, to the issuance of 94,000 shares following the exercise of stock options and to the DRIP, partly offset by the purchase and cancellation of 483,876 shares under the Corporation's normal course issuer bid. Also, the increase in the number of stock options outstanding since September 30, 2015, is attributable mainly to the issuance of 125,748 stock options to Innergex employees, partly offset by the exercise of 94,000 stock options.

LIQUIDITY AND CAPITAL RESOURCES

For the nine-month period ended September 30, 2016, the Corporation generated cash flows from operating activities of $104.7 million, compared with the use of $0.8 million for the same period last year. During this nine-month period, the Corporation generated funds from financing activities of $147.9 million and used funds for investing activities of $242.3 million, mainly to pay for the construction of its Development Projects and the acquisition of Seven French Entities in France. As at September 30, 2016, the Corporation had cash and cash equivalents amounting to $49.2 million, compared with $40.7 million as at December 31, 2015.

Cash Flows from Operating Activities

For the nine-month period ended September 30, 2016, cash flows generated by operating activities totalled $104.7 million ($0.8 million used in 2015). The change of $105.5 million was attributable mainly to the $119.6 million realized net loss on derivative financial instruments realized in 2015.

Cash Flows from Financing Activities

For the nine-month period ended September 30, 2016, cash flows generated by financing activities totalled $147.9 million (compared with $340.3 million generated in 2015). The cash flows from the financing activities are attributable mainly to a $147.1 million net increase in long-term debt and $50.0 million from a private placement of common shares of Innergex with three Desjardins Group-affiliated entities, partly offset by the payment of $52.5 million in dividends.

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

The $147.1 million net increase in long-term debt is attributable mainly to the $642.3 million in additional funds from the Development Projects-level debts, partly reduced by the repayment of $493.0 million of long-term debt (including revolving term credit facility).

Use of Financing Proceeds	Nine months ended September 30	
	2016	2015
Proceeds from issuance of long-term debt (including revolving term credit facility)	642,267	900,352
Repayment of long-term debt (including revolving term credit facility)	(493,007)	(546,813)
Payment of deferred financing costs	(2,171)	(8,469)
Sub-total: net increase in long-term debt	147,089	345,070
Proceeds from issuance of common shares	50,000	—
Net proceeds from issuance of convertible debentures	—	95,533
Payment of redemption of convertible debentures	—	(41,591)
Payment of buy-back of common shares	—	(7,271)
Proceeds from exercise of share options	1,034	394
Investments from non-controlling interests	6,392	—
Generation of financing proceeds	204,515	392,135
Business acquisitions	(102,795)	—
Realized loss on derivative financial instruments	—	(119,557)
Decrease (increase) of restricted cash and short-term investments	186,441	(141,355)
Net funds withdrawn from (invested into) the reserve accounts	246	(2,621)
Additions to property, plant and equipment	(323,407)	(189,840)
Additions to project development costs	—	(29,104)
Additions to other long-term assets	(14,668)	(426)
Net use of financing proceeds	(254,183)	(482,903)
Reduction in working capital	(49,668)	(90,768)

During the nine-month period ended September 30, 2016, the Corporation borrowed $642.3 million, mainly to pay for the construction of the Development Projects and for the reduction in drawings under the revolving term credit facility, to realize the acquisition of the Walden facility and the Seven French Entities and to make a deposit on the French entity to be acquired upon commissioning. It also used $186.4 million in restricted cash to continue construction of the Development Projects.

During the nine-month period ended September 30, 2015, the Corporation borrowed $900.4 million mainly to pay for construction of the Development Projects, the reduction in drawings under the revolving term credit facility and the $119.6 million realized loss on derivative financial instruments resulting from the settlement of the Boulder Creek, Upper Lillooet River, Big Silver Creek and Mesgi'g Ugju's'n bond forward contracts. It also increased restricted cash by $141.4 million, as the use of cash to pay for construction costs related to the Development Projects was more than offset by the addition of proceeds received from the projects' debts.

Cash Flows from Investing Activities

For the nine-month period ended September 30, 2016, cash flows used by investing activities amounted to $242.3 million ($363.3 million in 2015). During this period, the main investing activities that impacted cash flows were as follows: additions to property, plant and equipment accounted for a $323.4 million outflow ($189.8 million outflow in 2015); fluctuations in restricted cash and short-term investments accounted for a $186.4 million inflow ($141.4 million outflow in 2015); additions to other long-term assets accounted for a $14.7 million outflow ($0.4 million outflow in 2015) from a deposit made for the acquisition of a wind farm in France; and business acquisitions accounted for an $102.8 million outflow (none in 2015) for the acquisition of the Walden Facility and the Seven French Entities. In 2015, the Corporation used $29.1 million for additions to project development costs.

Cash and Cash Equivalents

As at September 30, 2016, the Corporation had cash and cash equivalents amounting to $49.2 million ($40.7 million as at December 31, 2015). For the nine-month period ended September 30, 2016, cash and cash equivalents increased by $8.5 million (decreased by $23.2 million in 2015) as a net result of its operating, financing and investing activities.

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

DIVIDENDS

The following dividends were declared by the Corporation:

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Dividends declared on common shares[1]	17,276	16,174	51,215	47,535
Dividends declared on common shares ($/share)	0.1600	0.1550	0.4800	0.4650
Dividends declared on Series A Preferred Shares	767	1,063	2,300	3,188
Dividends declared on Series A Preferred Shares ($/share)	0.2255	0.3125	0.6765	0.9375
Dividends declared on Series C Preferred Shares	719	719	2,157	2,157
Dividends declared on Series C Preferred Shares ($/share)	0.359375	0.359375	1.078125	1.078125

1. The increase in dividends declared on common shares is mainly attributable to the dividend increase, to the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex, to the issuance of 94,000 shares following the exercise of stock options as well as to the issuance of 249,131 shares under the DRIP, partly offset by the purchase and cancellation of 483,876 shares under the Corporation's normal course issuer bid.

The following dividends will be paid by the Corporation on January 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 ($)
11/09/2016	12/30/2016	1/16/2017	0.1600	0.2255	0.359375

On February 24, 2016, the Board of Directors increased the annual dividend from $0.62 to $0.64 per common share, payable quarterly.

FINANCIAL POSITION

As at September 30, 2016, the Corporation had $3,465 million in total assets, $2,988 million in total liabilities, including $2,496 million in long-term debt, and $477.0 million in shareholders' equity. The Corporation also had a working capital ratio of 1.19:1.00 (2.15:1.00 as at December 31, 2015). In addition to cash and cash equivalents amounting to $49.2 million, the Corporation had restricted cash and short-term investments of $126.3 million and reserve accounts of $49.1 million. The explanations below highlight the most significant changes in the statement of financial position items during the nine-month period ended September 30, 2016.

Assets

Highlights of significant changes in total assets during the nine-month period ended September 30, 2016

- A $177.9 million net decrease in cash and cash equivalents and restricted cash and short-term investments, due mainly to the amounts used to pay for Development Project construction costs, partly offset by cash and cash equivalents from the French Acquisition;
- A $430.9 million increase in property, plant and equipment, due mainly to the construction of the Development Projects, the acquisition of the Walden facility on February 25, 2016, and the purchase on April 15, 2016, of the Seven French Entities, partly offset by the depreciation for the period;
- A $63.5 million increase in intangible assets, due mainly to the acquisition of the Walden facility and the purchase of the Seven French Entities, partly offset by the amortization for the period; and
- A $13.9 million increase in other long term assets, due mainly to a deposit in view of the acquisition, upon commissioning, of an eighth wind project in France.

Working Capital Items

Working capital was positive at $35.3 million, as at September 30, 2016, with a working capital ratio of 1.19:1.00. As at December 31, 2015, working capital was positive at $212.2 million, with a working capital ratio of 2.15:1.00. The decrease in the working capital ratio is due mainly to a $186.4 million decrease in restricted cash and short-term investments.

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 September 30, 2016, the Corporation had drawn $155.4 million and US$13.9 million as cash advances, while $64.7 million had been used for issuing letters of credit.

Cash and cash equivalents amounted to $49.2 million as at September 30, 2016, compared with $40.7 million as at December 31, 2015. The increase stems mainly from higher revenues since the beginning of the year and from the purchase of the Seven French Entities.

Restricted cash and short-term investments amounted to $126.3 million as at September 30, 2016, compared with $312.7 million as at December 31, 2015. The decrease stems mainly from the amounts used to pay for construction of the Development Projects.

Accounts receivable decreased from $37.1 million to $35.2 million between December 31, 2015, and September 30, 2016, due mainly to commodity taxes received from construction of the Development Projects.

Accounts payable and other payables from December 31, 2015, to September 30, 2016, decreased from $95.5 million to $84.1 million, due mainly to payment of construction holdbacks and accounts payable by the Tretheway Creek, Big Silver Creek and Mesgi'g Ugju's'n projects, partly offset by additional construction activity at the Boulder Creek and Upper Lillooet River projects.

Current portion of long-term debt amounted to $65.8 million as at September 30, 2016, compared with $55.0 million as at December 31, 2015 . The increase stems mainly from Stardale's long-term debt increase on its borrowing and from the purchase of the Seven French Entities.

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 regime 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 $48.6 million in long-term reserve accounts as at September 30, 2016, compared with $41.5 million as at December 31, 2015. The increase is due to mandatory reserves from the Seven French Entities. The availability of funds in the hydrology/wind and major maintenance reserve accounts are in large part 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 September 30, 2016, the Corporation had $2,605 million in property, plant and equipment , compared with $2,174 million as at December 31, 2015. The increase stems mainly from the construction of the Development Projects, the purchase of the Walden facility on February 25, 2016, and the acquisition on April 15, 2016, of seven wind power projects in France, partly offset by depreciation.

Intangible assets

Intangible assets consist of various power purchase agreements, permits and licenses. They also include the extended warranty for the Montagne Sèche and Gros-Morne wind farm turbines. The Corporation had $535.8 million in intangible assets as at September 30, 2016, compared with $472.3 million as at December 31, 2015. The increase is due mainly to the acquisition of the Walden facility and the acquisition of seven wind power projects in France on April 15, 2016, partly offset by amortization.

Investments in Joint Ventures

Investments in joint ventures represent the Corporation's ownership portion of joint ventures, which are accounted for using the equity method. As at September 30, 2016, the Corporation had $7.1 million in investments in joint ventures, compared with $9.3 million as at December 31, 2015. This $2.3 million decrease reflects a portion of $0.1 million in distributions from Viger-Denonville, L.P. made by the joint venture to the Corporation during the period and the recognition of a $1.7 million distribution related to the Umbata Falls Facility. The other portion of $0.9 million in distributions received from Viger-Denonville, L.P. has been recorded in other long-term liabilities, while the partnership's net loss has not been recorded. Please refer to the Investments in Joint Ventures section for more information.

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 $582.9 million as at September 30, 2016.

As part of the acquisition of the wind farms in France, the Corporation entered into hedge agreements to reduce its foreign exchange risk on a portion of the distributions expected to be repatriated from France over the next 25 years following the acquisition of the Seven French Entities on April 15, 2016. The foreign exchange forwards, amortized until 2041, are translated to Canadian dollars from euros at a rate of 1.7575. The forwards contracts mature in 2018. As at the date of this MD&A, the Corporation had €93.5 million (C$164.4 million) in foreign exchange forward contracts outstanding (it had no euro foreign exchange forward contracts as at December 31, 2015).

Again, as part of the acquisition of the Seven French Entities, one of the wind farm entities holds a hedge agreement to mitigate the risk of fluctuations in the interest rates on its long-term debt. The interest rate swap is amortized over time. The interest rate swap matures in 2030. As at the date of this MD&A, the Corporation had C$15.3 million in interest rate swap outstanding (it had no interest rate swap for a foreign project as at December 31, 2015).

Overall, Derivatives had a net negative value of $87.7 million at September 30, 2016 (net negative value of $67.7 million at December 31, 2015). The increase in negative value is due mainly to the drop in benchmark interest rates since the end of 2015 and to the increase in the foreign exchange rates on the Corporation's foreign exchange forwards. These figures exclude the impact of Derivatives used to hedge loans of the Corporation's joint ventures. For information on the impact of derivative financial instruments used in the Corporation's joint ventures, please refer to the Investments in Joint Ventures section.

Long-Term Debt

As at September 30, 2016, long-term debt totalled $2,496 million ($2,215 million as at December 31, 2015). The $280.6 million increase results mainly from the addition of the Seven French Entities project-level debts, the issuance of a $32.0 million debenture carrying an interest rate of 8.0% to Desjardins for its investment in the French Acquisition, additional drawings on Innergex's credit facility, Stardale's long-term debt increase on its borrowing and additional drawings on Upper Lillooet and Mesgi'g Ugju's'n's financings, partly offset by the scheduled repayment of project-level debts.

On January 18, 2016, the Corporation executed an amending agreement to extend its revolving term credit facility from 2019 to 2020.

On February 22, 2016, Stardale renegotiated its long-term debt to increase its borrowing by $12.1 million for a total of $109.0 million. The loan bears interest at the BA rate plus an applicable credit margin that was reduced upon refinancing for a total floating-rate of 2.48% at refinancing. The principal repayments are variable and are set at $6.1million for the 12-month period following the refinancing. The all-in effective interest rate is 5.36% (5.99% previously) after accounting for the interest rate swap.

On June 10, 2016, the Corporation announced Desjardins' investment in the wind project portfolio acquired in France and a project under construction to be acquired at a later date. Following this investment, Desjardins owns 30.45% of Innergex Europe (2015) Limited Partnership, the limited partnership that holds these projects. Desjardins' initial investment is $38.4 million, of which $32.0 million was lent to the partnership through a debenture facility, carrying an interest rate of 8.0%.

As at September 30, 2016, 99% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (99% as at December 31, 2015).

Since the beginning of the 2016 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.

Other liabilities

Other liabilities usually consist of contingent considerations, asset retirement obligations and interests payable on the SM-1 LP debenture relating to the Corporation's facilities. Since the first quarter of 2016, it has also included a portion of the distributions made by Viger-Denonville, L.P. to Innergex, as explained in greater detail in the Investments in Joint Ventures section.

As at September 30, 2016, other liabilities totalled $22.2 million ($13.4 million as at December 31, 2015). The $8.8 million increase results mainly from the addition of $4.7 million in asset retirement obligations from the Seven French Entities Acquired, $2.9 million in interests payable on the SM-1 LP debenture and a $0.9 million portion of the distributions made by Viger-Denonville, L.P. to Innergex.

Shareholders' Equity

As at September 30, 2016, the Corporation's shareholders' equity totalled $477.0 million, including $13.2 million of non-controlling interests, compared with $471.6 million as at December 31, 2015, and which included $21.9 million of non-controlling interests. This $5.5 million increase in total shareholders' equity is attributable mainly to the realization of $23.3 million in net earnings, to the issuance of 3,906,250 shares for a value of $50.0 million to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex and $2.3 million in shares issued under the DRIP, partly offset by $55.7 million in dividends declared on common and preferred shares, and to the recognition of other items of comprehensive loss totalling $16.3 million.

For the nine-month period ended September 30, 2016, the Corporation recognized under the other items of comprehensive loss a $20.1 million unrealized net loss on derivative financial instruments due mainly to the decrease in benchmark interest rates since December 31, 2015.

Off-Balance-Sheet Arrangements

As at September 30, 2016, the Corporation had issued letters of credit totaling $118.4 million to meet its obligations under its various PPAs and other agreements. Of this amount, $64.7 million was issued under its revolving term credit facility, for the most part on a temporary basis during the construction of the Development Projects, with the remainder being issued under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $30.6 million in corporate guarantees used mainly to support the performance of the Brown Lake hydroelectric facility and the construction of the Mesgi'g Ugju's'n project.

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.

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

Free Cash Flow and Payout Ratio calculation	Trailing 12 months ended September 30 2016	2015
Cash flows from operating activities	110,026	29,616
Add (Subtract) the following items:		
Changes in non-cash operating working capital items	22,767	(21,045)
Maintenance capital expenditures net of proceeds from disposals	(3,920)	(3,145)
Scheduled debt principal payments	(43,028)	(32,008)
Free Cash Flow attributed to non-controlling interests[1]	(6,137)	(4,963)
Dividends declared on Preferred shares	(6,238)	(7,125)
Cash receipt for wheeling services to be provided by the Harrison Hydro L.P. to other facilities[2]	—	3,327
Adjust for the following elements:		
Transaction costs related to realized acquisitions	2,377	3
Realized losses on derivative financial instruments	—	119,557
Free Cash Flow	75,847	84,217
Dividends declared on common shares	67,326	62,636
Payout Ratio - before the impact of the DRIP	89%	74%
Dividends declared on common shares and paid in cash[3]	64,116	54,465
Payout Ratio - after the impact of the DRIP	85%	65%

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. These amounts represent cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to the Big Silver Creek and Tretheway Creek facilities respectively, 49.99% of which was included in the Free Cash Flow attributed to non-controlling interests.
3. 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 12 months ended September 30, 2016, the Corporation generated Free Cash Flow of $75.8 million, compared with $84.2 million for the same period last year. This decrease in Free Cash Flow is due mainly to higher cash flows from operations in 2016 before changes in non-cash operating working capital items and realized losses on derivative financial instruments, which were more than offset by greater scheduled debt principal payments.

Payout Ratio

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

For the trailing 12-month period on ended September 30, 2016, the dividends on common shares declared by the Corporation amounted to 89% of Free Cash Flow, compared with 74% for the corresponding prior 12-month period. This negative change is due mainly to the decrease in Free Cash Flow explained above and to the 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 common shares of Innergex, to the issuance of 94,000 shares following the exercise of stock options and to the DRIP, partly offset by the purchase and cancellation of 483,876 shares under the Corporation's normal course issuer bid.

The Payout Ratio reflects the Corporation's decision to invest each year 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 12-month period ended on September 30, 2016, the Corporation incurred prospective project expenses of $10.5 million, compared with $6.5 million for the corresponding prior period. This 61% 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 on September 30, 2016, and approximately 5% points lower for the corresponding prior period.

Furthermore, the Corporation does not expect to require additional equity in order to complete its current three Development Projects, given the anticipated increase in cash flows from operations once these projects have been commissioned, the project-level financing that the Corporation has secured for the projects and the additional equity provided by the DRIP.

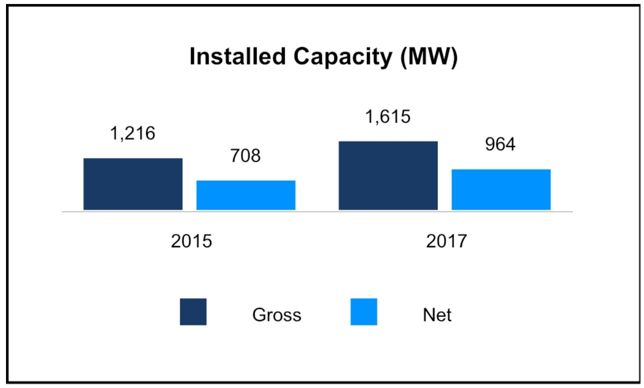
OUTLOOK FOR 2017

The Corporation makes certain projections to provide readers with an indication of its business activities and operating performance once the three existing Development Projects have been commissioned. These projections also include the data for the Walden Facility and the Seven French Entities Acquired, which were acquired by the Corporation in the first and second quarters of 2016, respectively and the Big Silver Creek facility commissioned in the third quarter of 2016. These projections do not take into account possible acquisitions, divestments or additional Development Projects following the award of any new power purchase agreements.

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

Projected Installed Capacity

The Corporation believes that installed capacity provides a good indication of the size and magnitude of its operations. Once the three Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities and the commissioning of Big Silver Creek in July 2016, the Corporation expects its net installed capacity to increase from 708 MW (gross 1,216 MW) at the end of the year 2015 to 964 MW (gross 1,615 MW) in 2017, corresponding to a 36% increase (gross 33%). Net installed capacity reflects the fact that some of the Corporation's Operating Facilities are not wholly owned. Installed capacity includes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method.



Projected Long-Term Average Production (LTA)

A key performance indicator for the Corporation is to compare actual electricity generation with the expected LTA production for each facility. Once the three Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities and the commissioning of Big Silver Creek in July 2016, the Corporation expects its annualized consolidated LTA production to increase from 3,130 GWh at the end of the year 2015 to 4,418 GWh in 2017, corresponding to a 41% increase. Consolidated LTA production is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method

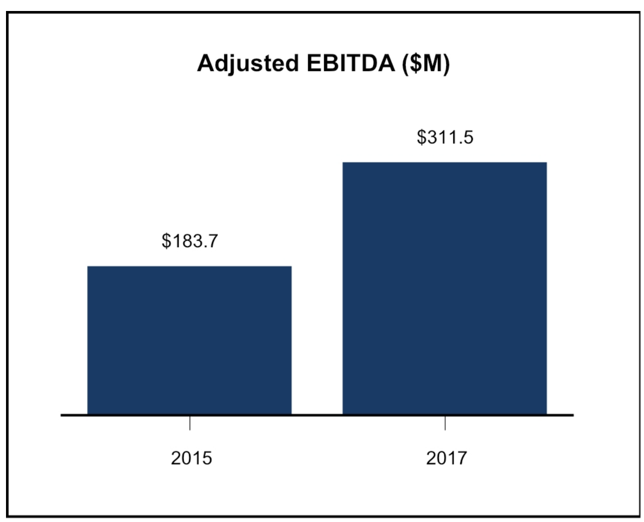
Annualized Consolidated LTA Production (GWh)

	2015	Starting in 2017
Hydro	2,415.9	3,019.4
Wind	676.5	1,360.9
Solar[1]	37.9	37.6
Total	3,130.3	4,417.9

1. Solar farm LTA diminishes over time due to expected solar panel degradation

Projected Adjusted EBITDA

A key performance indicator for the Corporation is Adjusted EBITDA generation. Once the three Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities and the commissioning of Big Silver Creek in July 2016, the Corporation expects to generate annualized Adjusted EBITDA starting in 2017 of approximately $311.5 million (adjusted for an inflation component thereafter), compared with $183.7 million in 2015. This represents an annual compound growth rate of approximately 30% for the 2015-2017 period. Adjusted EBITDA is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method. The annual Adjusted EBITDA for these facilities combined attributable to the Corporation is approximately $8.0 million.

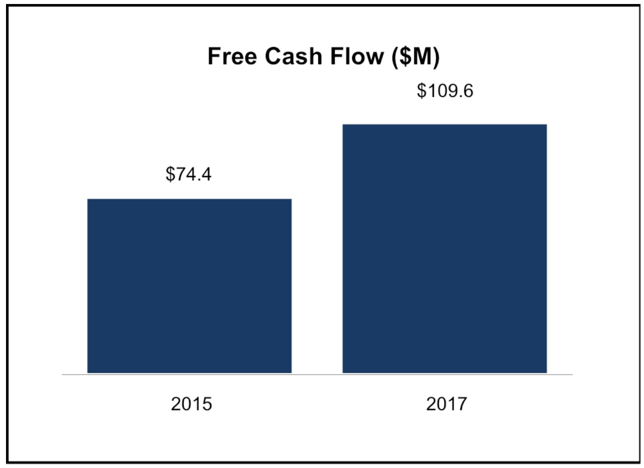


It should be noted that Adjusted EBITDA does not take into account the impact of interest and principal payments on the Corporation's existing debt and on the project-level debt financing.

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

Projected Free Cash Flow

Another key performance indicator for the Corporation is the Free Cash Flow generated from its operations and available for distribution to common shareholders and for reinvestment to fund its growth. Once the three Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities and the commissioning of Big Silver Creek in July 2016, the Corporation expects to generate Free Cash Flow in 2017 of approximately $109.6 million, compared with $74.4 million in 2015. This represents an annual compound growth rate of approximately 21% for the 2015-2017 period and will reflect the cash flows generated by the Corporation's 46 Operating Facilities at that time, after taking into account maintenance capital expenditures, scheduled debt principal payments, preferred share dividends and the portion of Free Cash Flow attributed to non-controlling interests. For 2017, the increase in Free Cash Flow of $4.6 million (to $109.6 million), compared with the information published as at December 31, 2015, is due mainly to the acquisition of the seven French wind farm facilities and the increase in production at the Mesgi'g Ugju's'n wind farm.



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

SEGMENT INFORMATION

Geographic Segments

As at September 30, 2016, the Corporation owns interests in 28 hydroelectric facilities, six wind farms and one solar farm in Canada, seven 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 September 30		Nine months ended September 30	
	2016	2015	2016	2015
Revenues				
Canada	65,206	61,082	210,335	186,967
France	2,400	—	5,212	—
United States	1,649	1,598	3,973	3,611
	69,255	62,680	219,520	190,578

As at	September 30, 2016	December 31,2015
Non-current assets, excluding financial instruments and deferred income tax assets		
Canada	2,971,057	2,704,788
France	247,465	—
United States	7,464	8,043
	3,225,986	2,712,831

Canada

For the three and nine-month period ended September 30, 2016, the Corporation recorded revenues in Canada of $65.2 million and $210.3 million respectively, compared with $61.1 million and $187.0 million for the same periods last year. For the three-month period, the increase in Canadian revenues is attributable mainly to better results from most of the British Columbia hydroelectric facilities compared with the same period last year and to the contribution of the recently commissioned and acquired facilities, namely the BC Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016 and the Big Silver Creek hydroelectric facility commissioned in July 2016, which were partly offset by lower revenues from the hydro and wind regime in Quebec and from the hydrologic regime in Ontario. In addition, for the nine-month period, the increase in Canadian revenues is attributable mainly to better results from most of the British Columbia hydroelectric facilities compared with the same period last year and to the contribution of the recently commissioned and acquired facilities, namely the BC Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016 and the Big Silver Creek hydroelectric facility commissioned in July 2016, which were partly offset by lower revenues from the wind regime in Quebec and from the hydrologic regime in Ontario.

For the period ended September 30, 2016, the increase in non-current assets, excluding financial instruments and deferred income tax assets in Canada, stems mainly from the construction of the Development Projects and the purchase of the Walden facility on February 25, 2016.

France

For the period ended and as at September 30, 2016, the increase in revenues and in non-current assets, excluding financial instruments and deferred income tax assets in France, stems mainly from the Seven French Entities acquired on April 15, 2016.

United States

For the three and nine-month period ended September 30, 2016, the Corporation recorded revenues in the United States of $1.6 million and $4.0 million respectively, compared with $1.6 million and $3.6 million for the same periods last year. The increase in United States revenues is attributable to better operating results from the Horseshoe Bend hydroelectric facility compared with the same period last year. For the period ended September 30, 2016, the decrease in non-current assets stems mainly from depreciation and foreign exchange fluctuations.

Operating Segments

As at September 30, 2016, the Corporation had four operating segments: hydroelectric generation, wind power generation, solar power generation and site development.

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

The accounting policies for these segments are the same as those described in the Significant Accounting Policies section of the Corporation's audited consolidated financial statements for the year ended December 31, 2015. The Corporation evaluates performance based on Adjusted EBITDA and accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind or solar power generation segments are accounted for at cost.

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

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

SUMMARY OPERATING RESULTS Three months ended September 30, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	672,950	144,970	13,920	—	831,840
Revenues	50,954	12,455	5,846	—	69,255
Expenses:					
Operating expenses	8,410	3,597	163	—	12,170
General and administrative expenses	1,714	797	29	375	2,915
Prospective project expenses	—	—	—	2,994	2,994
Adjusted EBITDA	40,830	8,061	5,654	(3,369)	51,176
Three months ended September 30, 2015					
Power generated (MWh)	630,567	134,377	13,031	—	777,975
Revenues	46,531	10,676	5,473	—	62,680
Expenses:					
Operating expenses	7,190	2,066	150	—	9,406
General and administrative expenses	1,621	729	33	609	2,992
Prospective project expenses	—	—	—	1,732	1,732
Adjusted EBITDA	37,720	7,881	5,290	(2,341)	48,550

SUMMARY OPERATING RESULTS Nine months ended September 30, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	2,108,847	527,670	36,161	—	2,672,678
Revenues	160,138	44,194	15,188	—	219,520
Expenses:					
Operating expenses	26,194	9,070	521	—	35,785
General and administrative expenses	5,698	2,948	109	1,791	10,546
Prospective project expenses	—	—	—	7,469	7,469
Adjusted EBITDA	128,246	32,176	14,558	(9,260)	165,720
Nine months ended September 30, 2015					
Power generated (MWh)	1,787,839	519,515	33,221	—	2,340,575
Revenues	135,169	41,456	13,953	—	190,578
Expenses:					
Operating expenses	22,445	6,774	534	—	29,753
General and administrative expenses	5,996	2,619	118	2,157	10,890
Prospective project expenses	—	—	—	5,015	5,015
Adjusted EBITDA	106,728	32,063	13,301	(7,172)	144,920

FINANCIAL POSITION As at September 30, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	—	—	—	8,269
Total assets	2,002,905	564,103	110,960	787,374	3,465,342
Total liabilities	1,558,022	384,374	116,912	929,020	2,988,328
Acquisition of property, plant and equipment during the period	3,864	157,849	—	314,637	476,350
As at December 31, 2015					
Goodwill	8,269	—	—	—	8,269
Total assets	1,806,873	332,698	114,543	874,189	3,128,303
Total liabilities	1,344,518	213,415	107,641	991,172	2,656,746
Acquisition of property, plant and equipment during the year	4,051	871	81	299,549	304,552

Hydroelectric Generation Segment

For the three-month period ended September 30, 2016, this segment produced 87% of the LTA and generated revenues of $51.0 million, compared with a production at 87% of the LTA and revenues of $46.5 million for the same period last year. Although production was generally stable between the two periods with respect to the percentage of the LTA achieved, the revenue increase in this segment is due mainly to production above the 2015 results for most of the British Columbia hydroelectric facilities during the quarter, to the contribution of the Tretheway Creek and Big Silver Creek hydroelectric facilities, which began commercial operation in November 2015 and July 2016 respectively, and to the contribution of the Walden North hydroelectric facility acquired in February 2016, which were partly offset by lower production in Quebec and Ontario.

For the nine-month period ended September 30, 2016, this segment produced 107% of the LTA and generated revenues of $160.1 million, compared with production at 96% of the LTA and revenues of $135.2 million for the same period last year. The revenue and production increases in this segment are due mainly to production above the long-term average in all jurisdictions except Ontario during the period, to the contribution of the Tretheway Creek and Big Silver Creek hydroelectric facilities, which began commercial operation in November 2015 and July 2016 respectively, and to the contribution of the Walden North hydroelectric facility acquired in February 2016.

The increase in total assets since December 31, 2015, stems mainly from the BC Big Silver Creek hydroelectric project being transferred from the Site Development Segment to the Hydroelectric Generation Segment following its commissioning in July 2016 and to the purchase of the Walden facility on February 25, 2016, which were partly offset by the depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2015, is attributable mainly to the transfer of the project financing of the BC Big Silver Creek project from the Site Development Segment to the Hydroelectric Generation Segment following its commissioning and to the purchase of the Walden facility on February 25, 2016, which were partly offset by the scheduled repayment of long-term debt.

Wind Power Generation Segment

For the three-month period ended September 30, 2016, this segment produced 102% of the LTA and generated revenues of $12.5 million, compared with production at 119% of the LTA and revenues of $10.7 million for the same period last year. The decrease of the LTA percentage compared to last year is due mainly to lower wind regimes at the Quebec facilities and the sub-LTA wind regime at the French facilities. The revenue increase is due to the French Acquisition.

For the nine-month period ended September 30, 2016, this segment produced 100% of the LTA and generated revenues of $44.2 million, compared with production at 111% of the LTA and revenues of $41.5 million for the same period last year. The decrease in the percentage of the LTA is also due mainly to lower wind regimes at the Quebec facilities and the sub-LTA wind regime at the French facilities. The revenue increase is due solely to the French Acquisition.

The increase in total assets since December 31, 2015, is attributable mainly to the French Acquisition, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2015, is attributable mainly to the French Acquisition, partly offset by the scheduled repayment of long-term debt.

Solar Power Generation Segment

For the three-month period ended September 30, 2016, this segment produced 111% of the LTA and generated revenues of $5.8 million, compared with production at 103% of the LTA and revenues of $5.5 million for the same period last year.

For the nine-month period ended September 30, 2016, this segment produced 112% of the LTA and generated revenues of $15.2 million, compared with production at 103% of the LTA and revenues of $14.0 million for the same period last year.

The increase in production and revenues for both the third quarter and the nine-month period stems mainly from solar irradiation higher than for the same period last year.

The decrease in total assets since December 31, 2015, results mainly from depreciation of property, plant and equipment and from amortization of intangible assets.

The increase in total liabilities since December 31, 2015, is attributable to Stardale's increase in its long-term debt borrowing, partly offset by scheduled repayments.

Site Development Segment

For the three-month and nine-month periods ended September 30, 2016, site development expenses were $3.4 million and $9.3 million respectively, compared with $2.3 million and $7.2 million respectively in 2015. The increase is due mainly to prospective project expenses incurred for the advancement of a number of Prospective Projects and to pursuing opportunities in new international markets.

The decrease in total assets since December 31, 2015, stems mainly from the BC Big Silver Creek hydroelectric project being transferred from the Site Development Segment to the Hydroelectric Generation Segment following its commissioning in July 2016.

Since December 31, 2015, the decrease in total liabilities has been due mainly to the BC Big Silver Creek hydroelectric project being transferred from the Site Development Segment to the Hydroelectric Generation Segment following its commissioning in July 2016, which was partly offset by drawings on the Boulder Creek, Upper Lillooet River and Mesgi'g Ugju's'n project financings.

QUARTERLY FINANCIAL INFORMATION

	Three months ended			
(in millions of dollars, unless otherwise stated)	Sept. 30, 2016	June 30, 2016	Mar. 31, 2016	Dec. 31, 2015
Power generated (MWh)	831,840	1,176,451	664,387	647,062
Revenues	69.3	87.8	62.5	56.3
Adjusted EBITDA	51.2	66.9	47.7	38.8
Realized and unrealized net (loss) gain on financial instruments	(1.3)	2.2	1.3	2.0
Impairment of project development costs	—	—	—	(51.7)
Net earnings (loss)	0.4	15.7	7.2	(34.4)
Net earnings (loss) attributable to owners of the parent	3.4	14.4	8.3	(30.6)
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.02	0.12	0.07	(0.31)
Dividends declared on preferred shares	1.5	1.5	1.5	1.8
Dividends declared on common shares	17.3	17.3	16.6	16.1
Dividends declared on common shares, $ per share	0.160	0.160	0.160	0.155

	Three months ended			
(in millions of dollars, unless otherwise stated)	Sept. 30, 2015	June 30, 2015	Mar. 31, 2015	Dec. 31, 2014
Power generated (MWh)	777,975	904,172	658,427	819,903
Revenues	62.7	70.2	57.7	68.2
Adjusted EBITDA	48.6	53.4	43.0	48.7
Realized and unrealized net (loss) gain on financial instruments	(2.7)	18.6	(56.0)	(49.6)
Impairment of project development costs	—	—	—	—
Net earnings (loss)	1.3	22.5	(37.8)	(27.6)
Net earnings (loss) attributable to owners of the parent	5.8	22.8	(29.1)	(18.9)
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.04	0.21	(0.31)	(0.21)
Dividends declared on preferred shares	1.8	1.8	1.8	1.8
Dividends declared on common shares	16.2	15.7	15.7	15.1
Dividends declared on common shares, $ per share	0.155	0.155	0.155	0.150

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

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 75% 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 factor responsible for the largest fluctuations in net earnings (loss) is the unrealized and realized gains (losses) on derivative financial instruments arising from the increase (decrease) in benchmark interest rates. Historical analysis of net earnings (losses) should take this factor 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 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 September 30	2016				2015			
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]
Umbata Falls	14,234	21,314	67%	84.87	19,310	21,314	91%	84.69
Viger-Denonville	12,924	16,350	79%	149.47	15,900	16,350	97%	149.13

Nine months ended September 30	2016				2015			
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]
Umbata Falls	83,627	76,064	110%	84.92	88,657	76,064	117%	84.80
Viger-Denonville	49,556	52,100	95%	149.47	59,985	52,100	115%	149.13

1. Corresponds to 100% of the facility's electricity production and LTA.
2. Including payments received from the ecoENERGY Initiative for Umbata Falls.

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

Umbata Falls, L.P.

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

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Revenues	1,208	1,636	7,102	7,518
Operating and general and administrative expenses	243	224	708	618
Adjusted EBITDA	965	1,412	6,394	6,900
Finance costs	626	649	1,890	1,920
Other net revenues	(8)	(6)	(24)	(27)
Depreciation and amortization	1,004	1,004	3,013	3,016
Unrealized net loss on financial instruments	193	1,040	2,316	1,450
Net (loss) earnings and comprehensive (loss) income	(850)	(1,275)	(801)	541

For the three- and nine-month periods ended September 30, 2016, production was 67% and 110% respectively of the LTA, due mainly to below-average water flows in the three-month period ended on September 30, 2016, but above-average results since the beginning of 2016.

The decrease in Adjusted EBITDA for the three-month period ended September 30, 2016, is due mainly to lower production levels than for the same period last year. For the nine-month period ended September 30, 2016, the Adjusted EBITDA was slightly lower in 2016 due to lower production compared with the previous period.

The net loss and comprehensive loss were $0.9 million for the three-month period ended September 30, 2016, compared with a net loss and comprehensive loss of $1.3 million for the same period last year. More specifically, for the three-month period ended September 30, 2016, Umbata Falls L.P. recognized a smaller $0.2 million unrealized net loss on financial instruments, compared with a $1.0 million unrealized net loss for the same period last year, the financial impact of which was partly offset by lower revenues in 2016. For the nine-month period ended September 30, 2016, Umbata Falls L.P. recorded a $0.8 million net loss and comprehensive loss, compared with $0.5 million in net earnings and comprehensive income for the same period last year. The loss for the nine-month period reflects the impact of a $2.3 million unrealized net loss on financial instruments, compared with a $1.5 million unrealized net loss for the same period last year and of a decrease in revenues. The unrealized losses on financial instruments result from the decrease in benchmark interest rates.

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

As at	September 30, 2016	December 31, 2015
Current assets	1,119	2,223
Non-current assets	65,646	68,467
	66,765	70,690
Current liabilities	2,972	3,062
Non-current liabilities	49,356	48,852
Partners' equity	14,437	18,776
	66,765	70,690

As at September 30, 2016, the reduction in partners' equity stems from the $0.8 million net loss generated for the nine-month period and a $3.5 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 $43.3 million used to hedge the interest rate on the Umbata Falls loan had a net negative value of $10.4 million at September 30, 2016 (negative value of $8.1 million at December 31, 2015).

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

Viger-Denonville, L.P.

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

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Revenues	1,932	2,371	7,407	8,946
Operating and general and administrative expenses	415	420	1,356	1,379
Adjusted EBITDA	1,517	1,951	6,051	7,567
Finance costs	908	909	2,744	2,738
Other net revenues	(11)	(8)	(22)	(39)
Depreciation and amortization	731	731	2,192	2,189
Unrealized net (gain) loss on financial instruments	(167)	(228)	(456)	1,800
Net earnings	56	547	1,593	879
Other comprehensive (loss) income	(228)	(1,330)	(2,448)	60
Total other comprehensive (loss) income	(172)	(783)	(855)	939

For the three- and nine-month periods ended September 30, 2016, production was 79% and 95% of the LTA respectively, due mainly to the below-average wind regime. The decrease in Adjusted EBITDA is due mainly to lower production levels than for the same periods last year.

On April 1, 2015, the Corporation began using hedge accounting in the treatment of existing derivative financial instruments used to fix the interest rate on the Viger-Denonville project-level debt in order to reduce the fluctuations in net earnings or losses resulting from unrealized gains or losses on these derivative financial instruments during a given period. Under hedge accounting, most of the unrealized gains or losses on derivative financial instruments that arise from a decrease or increase in the benchmark interest rate will be recorded as other comprehensive income or loss.

For the three-month period ended on September 30, 2016, the decrease in net earnings, compared with the net earnings for the same period last year, is due mainly to lower production levels. For the nine-month period ended on September 30, 2016, the increase in net earnings, compared with the net earnings for the same period last year, is due mainly to the recognition of an unrealized net gain on financial instruments compared with an unrealized net loss in the comparative period in 2015, partly offset by higher production levels in 2015.

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

As at	September 30, 2016	December 31, 2015
Current assets	1,850	2,426
Non-current assets	57,340	59,518
	59,190	61,944
Current liabilities	4,401	4,500
Non-current liabilities	57,392	57,191
(Deficit) Partners' equity	(2,603)	253
	59,190	61,944

As at September 30, 2016, the reduction in partners' equity stems mainly from a $2.0 million distribution and from the recognition of another comprehensive loss for the nine-month period. In addition, 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 $52.4 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $8.2 million at September 30, 2016 (negative $6.2 million at December 31, 2015).

During the first quarter of 2016, a distribution made by Viger-Denonville, L.P. to its partners turned the partnership's equity to a deficit. As such and as per Innergex's accounting policies, the Corporation discontinued recognizing its share of losses in Viger-Denonville, L.P. Furthermore, as the partners' equity is in a deficit position, the portion of the distributions made by the partnership to Innergex is recorded in other long-term liabilities in Innergex's Statements of Financial Position.

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

NON-WHOLLY OWNED SUBSIDIARIES

On June 10, 2016, Innergex announced the closing of the investment by Desjardins in the French Acquisition. Following this investment, the Corporation and Desjardins respectively hold 69.55% and 30.45% of the limited partnership that holds these projects. Summarized financial information regarding Innergex Europe (2015) Limited Partnership and its subsidiaries, in which Desjardins has a material non-controlling interest, is set out below. Amounts are shown before intragroup eliminations.

Innergex Europe (2015) Limited Partnership and Its Subsidiaries

On April 15, 2016, Innergex completed the acquisition of seven operating wind power projects in France. The Corporation realized the acquisition through wholly owned foreign subsidiaries of Innergex Europe (2015) Limited Partnership. Up to the investment made by Desjardins, 100% of the units of Innergex Europe (2015) Limited Partnership were owned by the Corporation. On June 10, 2016, Desjardins invested $38.4 million in exchange for 30.45% of the common units and a $32.0 million debenture issued by Innergex Europe (2015) Limited Partnership. The participation in the common units is reflected in the non-controlling interest account.

Summary Statements of Earnings and Comprehensive Income – Innergex Europe (2015) Limited Partnership and Its Subsidiaries

	Period of 169 days ended September 30, 2016
Revenues	5,212
Adjusted EBITDA	2,882
Net loss	(10,239)
Other comprehensive loss	(348)
Total comprehensive loss	(10,587)
Net loss attributable to:	
Owners of the parent	(7,857)
Non-controlling interests	(2,382)
	(10,239)
Total comprehensive loss attributable to :	
Owners of the parent	(8,115)
Non-controlling interests	(2,472)
	(10,587)

Since the April 15, 2016, acquisition and up to September 30, 2016, production was 67% of the LTA, due mainly to the below-average wind regime in France. The net loss for the period is due mainly to lower revenues, which result from below-average production, and to acquisition and financing costs. The financing costs include $0.8 million of interest payable to Desjardins on the $32.0 million debenture, $2.8 million of preferred return payable to Innergex on the $73.1 million preferred units and $0.6 million of interest payable to Innergex on a temporary bridge loan. Excluding these three elements, the net loss would have been $6.1 million. Expenses also include non-cash expenses such as depreciation and amortization of a total of $6.3 million.

Although the Corporation acquired the Seven French Entities in the second quarter, it is worth mentioning that for the nine-month period ended September 30, 2016, production was 96% of the LTA for the seven wind farms in France. This is due primarily to production that was 118% of the LTA in the first quarter of 2016 despite production having been below-average since the acquisition.

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

Summary Statements of Financial Position – Innergex Europe (2015) Limited Partnership and Its Subsidiaries

As at	September 30, 3016
Current assets	7,042
Non-current assets	250,743
	257,785
Current liabilities	13,062
Non-current liabilities	251,012
Deficit attributable to owners	(4,374)
Non-controlling interests	(1,915)
	257,785

Seven French Entities

The following figures are excluded from the controls policies and procedures of the Corporation as stated in the Establishment and Maintenance of DC&P and ICFR section of this MD&A.

Summary financial information about the Seven French Entities is set out below:

Summary Statements of Earnings and Comprehensive Income – Seven French Entities

	Period of 169 days ended September 30, 2016
Revenues	5,212
Adjusted EBITDA	3,000
Net loss	(3,649)
Other comprehensive loss	(89)
Total comprehensive loss	(3,738)

Summary Statements of Financial Position – Seven French Entities

As at	September 30, 3016
Current assets	5,978
Non-current assets	232,724
	238,702
Current liabilities	13,312
Non-current liabilities	180,528
Equity attributable to owners	44,862
	238,702

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

ACCOUNTING CHANGES

New and revised IFRS issued

IAS 1 - Presentation of Financial Statements

The IASB issued Disclosure Initiative (Amendments to IAS 1), which addressed concerns expressed about some of the existing presentation and disclosure requirements in IAS 1 and ensured that entities are able to use judgment when applying those requirements. In addition, the amendments clarified the requirements in other comprehensive income. Those amendments must be applied for annual periods beginning on or after January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

IAS 7 - Statement of cash flow

The IASB issued Disclosure Initiative (Amendments to IAS 7), which addressed that entities shall provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities. Those amendments must be applied for annual periods beginning on or after January 1, 2017. The Corporation is evaluating the impact this standard is expected to have on its consolidated financial statements.

IAS 12 - Income taxes

The IASB issued Amendments to IAS 12, which concluded that the diversity in practice around the recognition of a deferred tax asset that is related to a debt instrument measured at fair value is mainly attributable to uncertainty about the application of some of the principles in IAS 12. Those amendments must be applied for annual periods beginning on or after January 1, 2017. The Corporation is evaluating the impact this standard is expected to have on its consolidated financial statements.

IFRS 11- Joint arrangement

IFRS 11 was amended in May 2014 to add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

SUBSEQUENT EVENTS

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 ($)
11/09/2016	12/30/2016	01/16/2017	0.1600	0.2255	0.359375

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

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

		Three months ended September 30		Nine months ended September 30	
		2016	2015	2016	2015
	Notes				
Revenues		69,255	62,680	219,520	190,578
Expenses					
Operating	4	12,170	9,406	35,785	29,753
General and administrative		2,915	2,992	10,546	10,890
Prospective projects		2,994	1,732	7,469	5,015
Earnings before finance costs, income taxes, depreciation, amortization, other net (revenues) expenses, share of loss (earnings) of joint ventures and unrealized net loss (gain) on financial instruments		51,176	48,550	165,720	144,920
Finance costs	5	24,923	22,075	69,025	63,032
Other net (revenues) expenses	6	(224)	27,200	(631)	119,679
Earnings (loss) before income taxes, depreciation, amortization, share of loss (earnings) of joint ventures and unrealized net loss (gain) on financial instruments		26,477	(725)	97,326	(37,791)
Depreciation	4,9	15,836	13,252	44,689	39,750
Amortization	4	7,280	5,541	19,999	16,621
Share of loss (earnings) of joint ventures		416	352	393	(704)
Unrealized net loss (gain) on financial instruments		1,312	(24,325)	(2,120)	(79,406)
Earnings (loss) before income taxes		1,633	4,455	34,365	(14,052)
Income tax expense (recovery of)					
Current		1,028	828	2,500	2,458
Deferred		196	2,311	8,583	(2,522)
		1,224	3,139	11,083	(64)
Net earnings (loss)		409	1,316	23,282	(13,988)
Net earnings (loss) attributable to:					
Owners of the parent		3,419	5,804	26,132	(532)
Non-controlling interests		(3,010)	(4,488)	(2,850)	(13,456)
		409	1,316	23,282	(13,988)
Weighted average number of common shares outstanding (in 000s)	7	108,021	102,975	106,451	101,712
Basic net earnings (loss) per share ($)	7	0.02	0.04	0.20	(0.06)
Diluted weighted average number of common shares outstanding (in 000s)	7	109,091	103,167	107,317	102,014
Diluted net earnings (loss) per share ($)	7	0.02	0.04	0.20	(0.06)

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) (unaudited)

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Net earnings (loss)	409	1,316	23,282	(13,988)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:				
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	421	662	(670)	1,286
Related deferred tax	(62)	(87)	91	(169)
Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries	(581)	(695)	428	(1,315)
Related deferred tax	147	91	(17)	173
Change in fair value of hedging instruments	(1,964)	(10,662)	(20,051)	(2,397)
Related deferred tax	523	2,811	5,310	632
Share of change in fair value of hedging instruments of joint venture	—	(665)	—	30
Related deferred tax	—	175	—	(8)
Share of non-controlling interests in foreign exchange gain on translation of self-sustaining foreign subsidiaries	111	—	84	—
Share of non-controlling interests in foreign exchange loss on the designated hedges on the investments in self-sustaining foreign subsidiaries	(166)	—	(166)	—
Share of non-controlling interests in change in fair value of hedging instruments	(121)	(580)	(1,480)	(316)
Related deferred tax	24	152	153	83
Other comprehensive loss	(1,668)	(8,798)	(16,318)	(2,001)
Total comprehensive (loss) income	(1,259)	(7,482)	6,964	(15,989)
Other comprehensive loss attributable to:				
Owners of the parent	(1,516)	(8,370)	(14,909)	(1,768)
Non-controlling interests	(152)	(428)	(1,409)	(233)
	(1,668)	(8,798)	(16,318)	(2,001)
Total comprehensive income (loss) attributable to:				
Owners of the parent	1,903	(2,566)	11,223	(2,300)
Non-controlling interests	(3,162)	(4,916)	(4,259)	(13,689)
	(1,259)	(7,482)	6,964	(15,989)

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) (unaudited)

As at	Notes	September 30, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents		49,158	40,663
Restricted cash and short-term investments		126,278	312,720
Accounts receivable		35,247	37,073
Reserve accounts		468	1,315
Income tax receivable		—	4
Derivative financial instruments		1,270	1,209
Prepaid and others		8,653	4,363
		221,074	397,347
Non-current assets			
Reserve accounts		48,623	41,521
Property, plant and equipment	9	2,605,117	2,174,222
Intangible assets		535,812	472,271
Investments in joint ventures		7,074	9,327
Derivative financial instruments		5,310	2,768
Deferred tax assets		12,971	15,356
Goodwill		8,269	8,269
Other long-term assets		21,092	7,222
		3,465,342	3,128,303

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) (unaudited)

As at	Notes	September 30, 2016	December 31, 2015
Liabilities			
Current liabilities			
Dividends payable to shareholders		18,784	17,892
Accounts payable and other payables		84,138	95,466
Income tax payable		1,534	1,234
Derivative financial instruments		15,098	15,337
Current portion of long-term debt		65,820	54,995
Current portion of other liabilities		433	246
		185,807	185,170
Non-current liabilities			
Construction holdbacks		3,331	—
Derivative financial instruments		79,153	56,348
Long-term debt	10	2,430,235	2,160,438
Other liabilities		22,213	13,429
Liability portion of convertible debentures		94,485	93,430
Deferred tax liabilities		173,104	147,931
		2,988,328	2,656,746
Shareholders' equity			
Common share capital		161,931	108,541
Contributed surplus from reduction of capital on common shares		775,413	775,413
Preferred shares		131,069	131,069
Share-based payment		2,167	2,174
Equity portion of convertible debentures		1,877	1,877
Deficit		(592,193)	(567,848)
Accumulated other comprehensive loss		(16,485)	(1,576)
Equity attributable to owners		463,779	449,650
Non-controlling interests		13,235	21,907
Total shareholders' equity		477,014	471,557
		3,465,342	3,128,303

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) (unaudited)

	Equity attributable to owners											
Nine months ended September 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 (loss)							26,132		26,132	(2,850)	23,282
Other items of comprehensive loss								(14,909)	(14,909)	(1,409)	(16,318)
Total comprehensive income (loss)	—	—	—	—	—	—	26,132	(14,909)	11,223	(4,259)	6,964
Common shares issued on April 15, 2016 : private placement (Note 3b))	3,906	50,000							50,000		50,000
Common shares issued through dividend reinvestment plan	178	2,278							2,278		2,278
Share-based payment					71				71		71
Share options exercised	94	1,112			(78)				1,034		1,034
Distributions to non-controlling interests									—	(5,638)	(5,638)
Investments from non-controlling interests							5,194		5,194	1,225	6,419
Dividends declared on common shares							(51,215)		(51,215)		(51,215)
Dividends declared on preferred shares							(4,456)		(4,456)		(4,456)
Balance September 30, 2016	108,116	161,931	775,413	131,069	2,167	1,877	(592,193)	(16,485)	463,779	13,235	477,014

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) (unaudited)

	Equity attributable to owners										
Nine months ended September 30, 2015	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) income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2015	100,672	62,224	784,482	131,069	2,050	1,340	(466,336)	(15)	514,814	47,411	562,225
Net loss							(532)		(532)	(13,456)	(13,988)
Other items of comprehensive loss								(1,768)	(1,768)	(233)	(2,001)
Total comprehensive (loss) income	—	—	—	—	—	—	(532)	(1,768)	(2,300)	(13,689)	(15,989)
Common shares issued through dividend reinvestment plan	687	7,417							7,417		7,417
Buyback of common shares	(706)	(742)	(5,265)				(1,264)		(7,271)		(7,271)
Share-based payment					153				153		153
Share options exercised	45	462			(68)				394		394
Convertible debentures converted into common shares	3,653	38,680				(648)	891		38,923		38,923
Redemption of convertible debentures						(692)	951		259		259
Equity portion of convertibles debentures issued (Net of $672 of deferred income taxes)						1,878			1,878		1,878
Distributions to non-controlling interests									—	(7,448)	(7,448)
Dividends declared on common shares							(47,535)		(47,535)		(47,535)
Dividends declared on preferred shares							(5,344)		(5,344)		(5,344)
Balance September 30, 2015	104,351	108,041	779,217	131,069	2,135	1,878	(519,169)	(1,783)	501,388	26,274	527,662

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) (unaudited)

	Notes	Nine months ended September 30 2016	2015
Operating activities			
Net earnings (loss)		23,282	(13,988)
Items not affecting cash:			
Depreciation	9	44,689	39,750
Amortization		19,999	16,621
Share of loss (earnings) of joint ventures		393	(704)
Unrealized net gain on financial instruments		(2,120)	(79,406)
Inflation compensation interest	5	3,772	3,165
Amortization of financing fees	5	785	530
Accretion of long-term debt and convertible debentures	5	1,099	725
Accretion expenses on other liabilities	5	387	473
Share-based payment		72	153
Deferred income taxes		8,583	(2,522)
Others		73	178
Interest on long-term debt and convertible debentures	5	62,295	57,442
Interest paid		(57,535)	(54,924)
Unrealized loss on contingent considerations		210	—
Distributions received from joint ventures		2,733	6,303
Current income tax expense		2,500	2,458
Net income taxes paid		(2,178)	(2,558)
Effect of exchange rate fluctuations		1,825	659
		110,864	(25,645)
Changes in non-cash operating working capital items	12	(6,182)	24,859
		104,682	(786)
Financing activities			
Dividends paid on common shares		(47,749)	(39,045)
Dividends paid on preferred shares		(4,752)	(5,343)
Distributions to non-controlling interests		(4,138)	(7,448)
Investments from non-controlling interests		6,392	—
Increase of long-term debt		642,267	900,352
Repayment of long-term debt		(493,007)	(546,813)
Payment of deferred financing costs		(2,171)	(8,469)
Payment for redemption of convertible debentures		—	(41,591)
Net proceeds from issuance of convertible debentures		—	95,533
Payment for buyback of common shares		—	(7,271)
Proceeds from issuance of common shares		50,000	—
Proceeds from exercise of share options		1,034	394
		147,876	340,299

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) (unaudited)

	Notes	Nine months ended September 30 2016	2015
Investing activities			
Cash acquired on business acquisitions	3	11,887	—
Business acquisitions	3	(102,795)	—
Decrease (increase) of restricted cash and short-term investments		186,441	(141,355)
Net funds withdrawn from (invested into) the reserve accounts		246	(2,621)
Additions to property, plant and equipment		(323,407)	(189,840)
Additions to project development costs		—	(29,104)
Additions to other long-term assets		(14,668)	(426)
Proceeds from disposal of property, plant and equipment		—	29
		(242,296)	(363,317)
Effects of exchange rate changes on cash and cash equivalents		(1,767)	592
Net increase (decrease) in cash and cash equivalents		8,495	(23,212)
Cash and cash equivalents, beginning of period		40,663	54,609
Cash and cash equivalents, end of period		49,158	31,397
Cash and cash equivalents is comprised of:			
Cash		48,240	12,419
Short-term investments		918	18,978
		49,158	31,397

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. (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 1111, St-Charles Street West, East Tower, Suite 1255, Longueuil, Qc, J4K 5G4, Canada.

These unaudited condensed consolidated financial statements were approved by the Board of Directors on November 9, 2016.

The Corporation's revenues are variable with each season and are normally at their lowest in the first quarter due to cold temperature. 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 NEW AND REVISED IFRS

New and revised IFRS issued

IAS 1 - Presentation of Financial Statements

The IASB issued Disclosure Initiative (Amendments to IAS 1), which addressed concerns expressed about some of the existing presentation and disclosure requirements in IAS 1 and ensured that entities are able to use judgment when applying those requirements. In addition, the amendments clarified the requirements in other comprehensive income. Those amendments must be applied for annual periods beginning on or after January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

IAS 7 - Statement of cash flow

The IASB issued Disclosure Initiative (Amendments to IAS 7), which addressed that entities shall provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities. Those amendments must be applied for annual periods beginning on or after January 1, 2017. The Corporation is evaluating the impact this standard is expected to have on its consolidated financial statements.

IAS 12 - Income taxes

The IASB issued Amendments to IAS 12, which concluded that the diversity in practice around the recognition of a deferred tax asset that is related to a debt instrument measured at fair value is mainly attributable to uncertainty about the application of some of the principles in IAS 12. Those amendments must be applied for annual periods beginning on or after January 1, 2017. The Corporation is evaluating the impact this standard is expected to have on its consolidated financial statements.

IFRS 11- Joint arrangement

IFRS 11 was amended in May 2014 to add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after

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

January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

3. BUSINESS ACQUISITIONS

a. Acquisition of assets of Walden

On February 25, 2016, the Corporation and Cayoose Creek Development Corporation ("Cayoose") finalized the acquisition of the Walden ("Walden") run-of-river hydroelectric facility located in British Columbia, Canada. The purchase price of $9,200 for the Walden facility was paid in cash, of which $870 was paid as a deposit in the fourth quarter of 2015 and was classified under other long-term assets as at December 31, 2015.

The Corporation and Cayoose respectively own 51% and 49% of the participating units of Cayoose Creek Limited Partnership ("Cayoose L.P."), formed for the acquisition of the Walden facility.

All power generated from the facility is sold to British Columbia Hydro and Power Authority.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. The acquisition of the Walden facility added an additional installed gross capacity of approximately 16 MW to the Corporation's portfolio of operational hydroelectric facilities.

The following table reflects the preliminary purchase price allocation:

	Preliminary purchase price allocation
Property, plant and equipment	1,786
Intangible assets	8,078
Deferred tax liabilities	(664)
Net assets acquired	9,200

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, 2016, the consolidated revenues and net earnings for the nine-month period ended September 30, 2016 would have been $219,633 and $23,232 respectively.

The amounts of revenues and net earnings of Cayoose LP since February 25, 2016 included in the consolidated statement of earnings are $2,099 and $895 respectively for the 219 days ended September 30, 2016.

b. Acquisition of 7 operating wind facilities in France

On April 15, 2016, the Corporation finalized the acquisition of a portfolio of 7 operating wind facilities located in France ("the Seven French Entities Acquired"). The purchase price for the wind power projects is a net cash consideration of €63,971 (equivalent to C$94,465), subject to certain adjustments.

In the first quarter of 2016 an amount of €10,100 (or C$14,700) was also paid as a deposit for a project currently under construction.

All power generated from the operating facilities is sold to Electricité de France and S.I.C.A.E Oise.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. The Seven French Entities Acquired added an additional gross installed capacity of 86.8 MW to the Corporation's portfolio of operational wind farms.

To finance part of the acquisition, three Desjardins Group affiliated entities have collectively subscribed to a private placement of 3,906,250 common shares of the Corporation for proceeds of $50,000.

The following table reflects the preliminary purchase price allocation:

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

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, 2016, the consolidated revenues and net earnings for the nine-month period ended September 30, 2016 would have been $228,640 and $24,339 respectively.

The amounts of revenues and net loss of the facilities since April 15, 2016 included in the consolidated statement of earnings are $5,212 and $6,889 respectively for the 169 days ended September 30, 2016.

4. OPERATING EXPENSES

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Salaries	1,178	994	3,274	3,042
Insurance	767	663	2,133	1,942
Operation and maintenance	5,132	3,625	14,531	12,270
Property taxes and royalties	5,093	4,124	15,847	12,499
	12,170	9,406	35,785	29,753

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

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

5. FINANCE COSTS

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Interest on long-term debt and on convertible debentures	22,582	18,571	62,295	57,442
Inflation compensation interest	1,326	2,480	3,772	3,165
Amortization of financing fees	276	142	785	530
Accretion of long-term debt and convertible debentures	329	448	1,099	725
Accretion expenses on other liabilities	155	163	387	473
Others	255	271	687	697
	24,923	22,075	69,025	63,032

6. OTHER NET (REVENUES) EXPENSES

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Transaction costs	426	—	1,692	—
Realized loss on derivative financial instruments	—	26,984	—	119,557
Realized (gain) loss on foreign exchange	(626)	463	(1,169)	1,024
Unrealized loss on contingent considerations	210	—	210	—
Other net revenues	(234)	(247)	(1,062)	(902)
Loss on disposal of property, plant and equipment	—	—	173	—
Recovery of loan impairment	—	—	(475)	—
	(224)	27,200	(631)	119,679

7. EARNINGS PER SHARE

The net earnings (loss) per share is computed as follows:

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Net earnings (loss) attributable to owners of the parent	3,419	5,804	26,132	(532)
Dividends declared on preferred shares	(1,485)	(1,781)	(4,456)	(5,344)
Net earnings (loss) available to common shareholders	1,934	4,023	21,676	(5,876)
Weighted average number of common shares (in 000s)	108,021	102,975	106,451	101,712
Basic net earnings (loss) per share ($)	0.02	0.04	0.20	(0.06)
Weighted average number of common shares (in 000s)	108,021	102,975	106,451	101,712
Effect of dilutive elements on common shares (in 000s) (a)	1,070	192	866	302
Diluted weighted average number of common shares (in 000s)	109,091	103,167	107,317	102,014
Diluted net earnings (loss) per share ($) (b)	0.02	0.04	0.20	(0.06)

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 period ended September 30, 2016, all of the 3,457,432 stock options (1,785,684 of the 3,425,684 for the three-month period ended September 30, 2015) were dilutive. During the nine-month period ended September 30, 2016, 3,331,684 of the 3,457,432 stock options (all of the 3,425,684 for the nine-month period ended September 30, 2015) were dilutive.

   During the three-month and nine-month periods ended September 30, 2016, 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 2015).

b. During the nine-month period ended September 30, 2015, all of the 3,425,684 stock options were excluded as they were anti-dilutive in the calculation of the diluted net loss per share.

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

8. DERIVATIVE FINANCIAL INSTRUMENTS

As part of the acquisition of the wind farms in France, the Corporation entered into hedge agreements to reduce the Corporation's foreign exchange risk.

Contracts	Maturity	Early termination option	Notional Amounts September 30, 2016	Notional Amounts December 31, 2015
Contracts for which hedge accounting is used:				
Foreign exchange forwards amortizing until 2041, translated at CAD1.7575/Euro	2018	None	164,375	—

As part of the acquisition of the wind farms in France, one of the wind farm holds hedge agreement to mitigate the risk of fluctuations in the interest rates on its long-term debt.

Contracts	Maturity	Early termination option	Notional Amounts September 30, 2016	Notional Amounts December 31, 2015
Contracts for which hedge accounting is used:				
Interest rate swap, 2.64%, amortizing, translated at CAD 1.4741/Euro	2030	None	15,331	—

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

9. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2016	2,623	1,427,025	372,038	124,274	531,591	9,194	2,466,745
Additions	—	1,799	396	—	314,187	852	317,234
Business acquisitions (Note 3)	286	1,500	157,322	—	—	8	159,116
Transfer of assets upon commissioning	—	183,556	—	—	(183,556)	—	—
Dispositions	—	(207)	—	—	—	—	(207)
Other changes	—	—	—	—	—	(263)	(263)
Net foreign exchange differences	(9)	(423)	(275)	—	—	2	(705)
As at September 30, 2016	2,900	1,613,250	529,481	124,274	662,222	9,793	2,941,920
Accumulated depreciation							
As at January 1, 2016	—	(164,117)	(100,307)	(21,820)	—	(6,279)	(292,523)
Depreciation	—	(22,525)	(16,483)	(4,466)	—	(1,215)	(44,689)
Dispositions	—	34	—	—	—	—	34
Other changes	—	—	—	—	—	263	263
Net foreign exchange differences	—	152	(40)	—	—	—	112
As at September 30, 2016	—	(186,456)	(116,830)	(26,286)	—	(7,231)	(336,803)
Carrying amount as at September 30, 2016	2,900	1,426,794	412,651	97,988	662,222	2,562	2,605,117

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

Additions in the current period include $30,693 of capitalized financing costs ($30,341 for the year ended December 31, 2015) 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 term credit facility are capitalized for the portion of the financing actually used for a specific property, plant and equipment.

The cost of facilities were reduced by investment tax credits of $2,909 ($2,622 as at December 31, 2015).

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

10. LONG-TERM DEBT

a. Revolving term credit facility

On January 18, 2016, the Corporation executed an amending agreement to extend its revolving term credit facility from 2019 to 2020.

b. Refinancing of Stardale long-term debt

On February 22, 2016, Stardale has renegotiated its long-term debt to increase its borrowing by $12,138 for a total of $109,000. The loan bears interest at the BA rate plus an applicable credit margin that has been reduced upon refinancing for a total floating-rate of 2.48% at refinancing. The principal repayments are variable and are set at $6,054 for the 12-month following the refinancing. The all-in effective interest rate is 5.36% (5.99% before) after accounting for the interest rate swap.

c. Long-term debt for wind farms in France

As part of the acquisition in France, the Corporation assumed the long-term debt of seven wind farms. Also, following this acquisition, a debenture was issued to finance a portion of the acquisition cost.

	Interests rate 2016	Maturity	September 30, 2016	December 31, 2015
Terms loans - France (Non-recourse to the Corporation and with an Euro currency origin)				
a) Cholletz, floating-rate term loan	1.90%	2017	2,211	—
b) Valottes, fixed rate term loan	2.69%	2024	6,755	—
c) Antoigné, fixed rate term loan	2.67%	2025	9,740	—
d) Bois d'Anchat, fixed rate term loan	3.20%	2025	1,482	—
e) Longueval, fixed rate term loan	1.86%	2025	8,241	—
e) Longueval, fixed rate term loan	1.67%	2025	3,139	—
f) Porcien, fixed rate term loan	1.86%	2025	8,241	—
f) Porcien, fixed rate term loan	1.67%	2025	3,499	—
b) Valottes, fixed rate term loan	1.80%	2026	11,827	—
g) Beaumont, fixed rate term loan	2.16%	2027	5,245	—
g) Beaumont, fixed rate term loan	2.63%	2027	1,394	—
d) Bois d'Anchat, fixed rate term loan	2.25%	2030	14,258	—
a) Cholletz, fixed rate term loan	2.23%	2030	15,331	—
g) Beaumont, fixed rate term loan	2.42%	2031	30,219	—
			121,582	—
Debenture - Canada (Non-recourse to the Corporation and with a CAD currency origin)				
h) Innergex Europe, fixed rate debenture	8.00%	2046	31,965	—
			153,547	—

Amounts below are in thousands of Euro.

a) Cholletz

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €11,900.

- A €1,500 loan bearing interest at 1.9%, repayable in quarterly installments and maturing in 2017. The principal repayments are set to €1,000 for the 12-month period following the acquisition.
- A €10,400 loan bearing interest at 2.23% until 2026 and at variable rate plus an applicable margin afterwards, repayable in quarterly installments and maturing in 2030. The principal will begin to be amortized in 2017.

The debt is secured by the assets of Energie des Cholletz S.A.S. with a carrying value of approximately €21,684.

b) Valottes

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €12,021.

- A €4,749 loan bearing interest at 2.69%, repayable in quarterly installments and maturing in 2024. The principal repayments are set to €374 for the 12-month period following the acquisition.

- A €7,273 loan bearing interest at 5.34%, repayable in quarterly installments and maturing in 2026. The principal repayments are set to €727 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $8,502 for an effective rate of 1.80%.

The debt is secured by the assets of Energie des Valottes S.A.S. with a carrying value of approximately €22,497.

c) Antoigné

As part of the Seven French Entities Acquired, the Corporation assumed a €6,964 term loan, bearing interest at 2.67%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €714 for the 12-month following the acquisition. The loan is secured by the assets of Energie Antoigné S.A.S. with a carrying value of approximately €14,200.

d) Bois d'Anchat

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €11,205.

- A €1,005 loan bearing interest at 3.20%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €19 for the 12-month following the acquisition.

- A €10,200 loan bearing interest at 2.25%, repayable in quarterly installments and maturing in 2030. The principal repayments are set to €704 for the 12-month following the acquisition.

The debt is secured by the assets of Société d'Exploitation du Parc Éolien du Bois d'Anchat with a carrying value of approximately €22,141.

e) Longueval

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €7,881.

- A €6,069 loan bearing interest at 1.86%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €799 for the 12-month period following the acquisition.

- A €1,812 loan bearing interest at 5.73%, repayable in semi-annual installments and maturing in 2025. The principal repayments are set to €70 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $2,186 for an effective rate of 1.67%.

The debt is secured by the assets of Eoliennes de Longueval S.A.S. with a carrying value of approximately €15,755.

f) Porcien

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €8,116.

- A €6,069 loan bearing interest at 1.86%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €799 for the 12-month period following the acquisition.

- A €2,047 loan bearing interest at 5.73%, repayable in semi-annual installments and maturing in 2025. The principal repayments are set to €111 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $2,454 for an effective rate of 1.67%.

The debt is secured by the assets of Energie du Porcien S.A.S. with a carrying value of approximately €15,935.

g) Beaumont

As part of the Seven French Entities Acquired, the Corporation assumed three loan facilities for a total value of €25,131.

- A €3,649 loan bearing interest at 3.78%, repayable in quarterly installments and maturing in 2027. The principal repayments are set to €430 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $3,999 for an effective rate of 2.16%.

- A €982 loan bearing interest at 2.63%, repayable in quarterly installments and maturing in 2027. The principal repayments are set to €36 for the 12-month period following the acquisition.

- A €20,500 loan bearing interest at 2.42%, repayable in quarterly installments and maturing in 2031. The principal repayments are set to €1,042 for the 12-month period following the acquisition.

The debt is secured by the assets of Eoles Beaumont S.A.S. with a carrying value of approximately €49,719.

h) Innergex Europe (2015) Limited Partnership

Following the Seven French Entities Acquired, a debenture was issued to the other partner for a total proceeds of $ 31,965. This debenture carries an interest rate of 8% compounded yearly and payable quarterly if funds are available. The debenture will be repayable in full in 2046. The Corporation invested a total of $73,011 in preferred units of Innergex Europe (2015) Limited Partnership which carries a preferred return rate of 8% compounded yearly and payable at the same time as the debenture. The preferred units are eliminated into the consolidation process.

11. SHAREHOLDERS' EQUITY

a. Stock option plan

During the third quarter of 2016, 94,000 share options have been exercised at $11.00 per share resulting in a $1,034 proceed.

Also 125,748 share options were granted during the quarter. The options granted under the stock option plan vest in equal amounts on a yearly basis over a period of four years following the grant date. Options must be exercised before August 2023 at an exercise price of $14.65.

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

12. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Nine months ended September 30	
	2016	2015
Accounts receivable and income tax receivable	4,608	(430)
Prepaid and others	(2,364)	(1,818)
Accounts payable and other payables and income tax liabilities	(8,426)	27,107
	(6,182)	24,859

b. Additional information

	Nine months ended September 30	
	2016	2015
Interest paid (including $30,039 capitalized interest ($18,845 in 2015))	87,574	73,769
Non-cash transactions		
in unpaid property, plant and equipment	(5,789)	1,378
in unpaid development costs	—	(4,218)
in unpaid transactions costs of convertible debentures	—	108
in common shares issued through the conversion of convertible debentures	—	(38,680)
in common shares issued through share options exercised	(78)	(68)
distribution unpaid to non-controlling interests in subsidiaries	(1,500)	—
in common shares issued through dividend reinvestment plan	(2,278)	(7,417)
loans to partners in exchange of non-controlling interests in subsidiaries	(27)	—

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

13. SUBSIDIARIES

Innergex Europe (2015) Limited Partnership and its subsidiaries

The Corporation owned 100% of the participating units of Innergex Europe (2015) Limited Partnership, formed for the acquisition of seven operating wind farms in France on April 15, 2016.

On June 10, 2016, Desjardins subscribed an amount of $38,357 in exchange of 30.45% of the common units and a debenture of $31,965 issued by Innergex Europe (2015) Limited Partnership.

The summarized financial information below represents amounts before intragroup eliminations.

As at	September 30, 2016
Summary Statement of Financial Position	
Current assets	7,042
Non-current assets	250,743
	257,785
Current liabilities	13,062
Non-current liabilities	251,012
Deficit attributable to owners	(4,374)
Non-controlling interests	(1,915)
	257,785

	Period of 169 days ended September 30, 2016
Summary Statement of Earnings and Comprehensive loss	
Revenues	5,212
Expenses [1]	15,451
Net loss	(10,239)
Other comprehensive loss	(348)
Total comprehensive loss	(10,587)
Net loss attributable to:	
Owners of the parent	(7,857)
Non-controlling interests	(2,382)
	(10,239)
Total comprehensive loss attributable to:	
Owners of the parent	(8,115)
Non-controlling interests	(2,472)
	(10,587)

1. Expenses include $784 of interest payable to Desjardins on the $31,965 debenture, $2,750 of preferred return payable to Innergex on the $73,011 preferred units and $600 of interest payable to Innergex on a temporary bridge loan. Excluding these three elements, the Net loss would have been $6,105. Expenses also include non-cash expenses such as depreciation and amortization of a total amount of $6,317.

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

14. SEGMENT INFORMATION

Geographic segments

The Corporation owns interests in 28 hydroelectric facilities, six wind farms and one solar farm in Canada, seven 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 September 30		Nine months ended September 30	
	2016	2015	2016	2015
Revenues				
Canada	65,206	61,082	210,335	186,967
France	2,400	—	5,212	—
United States	1,649	1,598	3,973	3,611
	69,255	62,680	219,520	190,578

As at	September 30, 2016	December 31,2015
Non-current assets, excluding financial instruments and deferred income tax assets		
Canada	2,971,057	2,704,788
France	247,465	—
United States	7,464	8,043
	3,225,986	2,712,831

Operating segments

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

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

The accounting policies for these segments are the same as those described in the significant accounting policies. The Corporation evaluates performance based on earnings (loss) before finance costs, income taxes, depreciation, amortization, other net (revenues) expenses , share of (earnings) loss of joint ventures and unrealized net (gain) loss on financial instruments. The Corporation accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind power generation or solar power generation segments are accounted for at cost.

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

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

Three months ended September 30, 2016 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	50,954	12,455	5,846	—	69,255
Expenses:					
Operating	8,410	3,597	163	—	12,170
General and administrative	1,714	797	29	375	2,915
Prospective projects	—	—	—	2,994	2,994
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of loss of joint ventures and unrealized net loss on financial instruments	40,830	8,061	5,654	(3,369)	51,176
Finance costs					24,923
Other net revenues					(224)
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net loss on financial instruments					26,477
Depreciation					15,836
Amortization					7,280
Share of loss of joint ventures					416
Unrealized net loss on financial instruments					1,312
Earnings before income taxes					1,633

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

Three months ended September 30, 2015 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	46,531	10,676	5,473	—	62,680
Expenses:					
Operating	7,190	2,066	150	—	9,406
General and administrative	1,621	729	33	609	2,992
Prospective projects	—	—	—	1,732	1,732
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of loss of joint ventures and unrealized net gain on financial instruments	37,720	7,881	5,290	(2,341)	48,550
Finance costs					22,075
Other net expenses					27,200
Loss before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net gain on financial instruments					(725)
Depreciation					13,252
Amortization					5,541
Share of loss of joint ventures					352
Unrealized net gain on financial instruments					(24,325)
Earnings before income taxes					4,455

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

Nine months ended September 30, 2016 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	160,138	44,194	15,188	—	219,520
Expenses:					
Operating	26,194	9,070	521	—	35,785
General and administrative	5,698	2,948	109	1,791	10,546
Prospective projects	—	—	—	7,469	7,469
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of loss of joint ventures and unrealized net gain on financial instruments	128,246	32,176	14,558	(9,260)	165,720
Finance costs					69,025
Other net revenues					(631)
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net gain on financial instruments					97,326
Depreciation					44,689
Amortization					19,999
Share of loss of joint ventures					393
Unrealized net gain on financial instruments					(2,120)
Earnings before income taxes					34,365

As at September 30, 2016					
Goodwill	8,269	—	—	—	8,269
Total assets	2,002,905	564,103	110,960	787,374	3,465,342
Total liabilities	1,558,022	384,374	116,912	929,020	2,988,328
Acquisition of property, plant and equipment during the period	3,864	157,849	—	314,637	476,350

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

Nine months ended September 30, 2015 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	135,169	41,456	13,953	—	190,578
Expenses:					
Operating	22,445	6,774	534	—	29,753
General and administrative	5,996	2,619	118	2,157	10,890
Prospective projects	—	—	—	5,015	5,015
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on financial instruments	106,728	32,063	13,301	(7,172)	144,920
Finance costs					63,032
Other net expenses					119,679
Loss before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					(37,791)
Depreciation					39,750
Amortization					16,621
Share of earnings of joint ventures					(704)
Unrealized net gain on financial instruments					(79,406)
Loss before income taxes					(14,052)

As at December 31, 2015					
Goodwill	8,269	—	—	—	8,269
Total assets	1,806,873	332,698	114,543	874,189	3,128,303
Total liabilities	1,344,518	213,415	107,641	991,172	2,656,746
Acquisition of property, plant and equipment during the year	4,051	871	81	299,549	304,552

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

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 ($)
11/09/2016	12/30/2016	01/16/2017	0.1600	0.2255	0.359375

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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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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