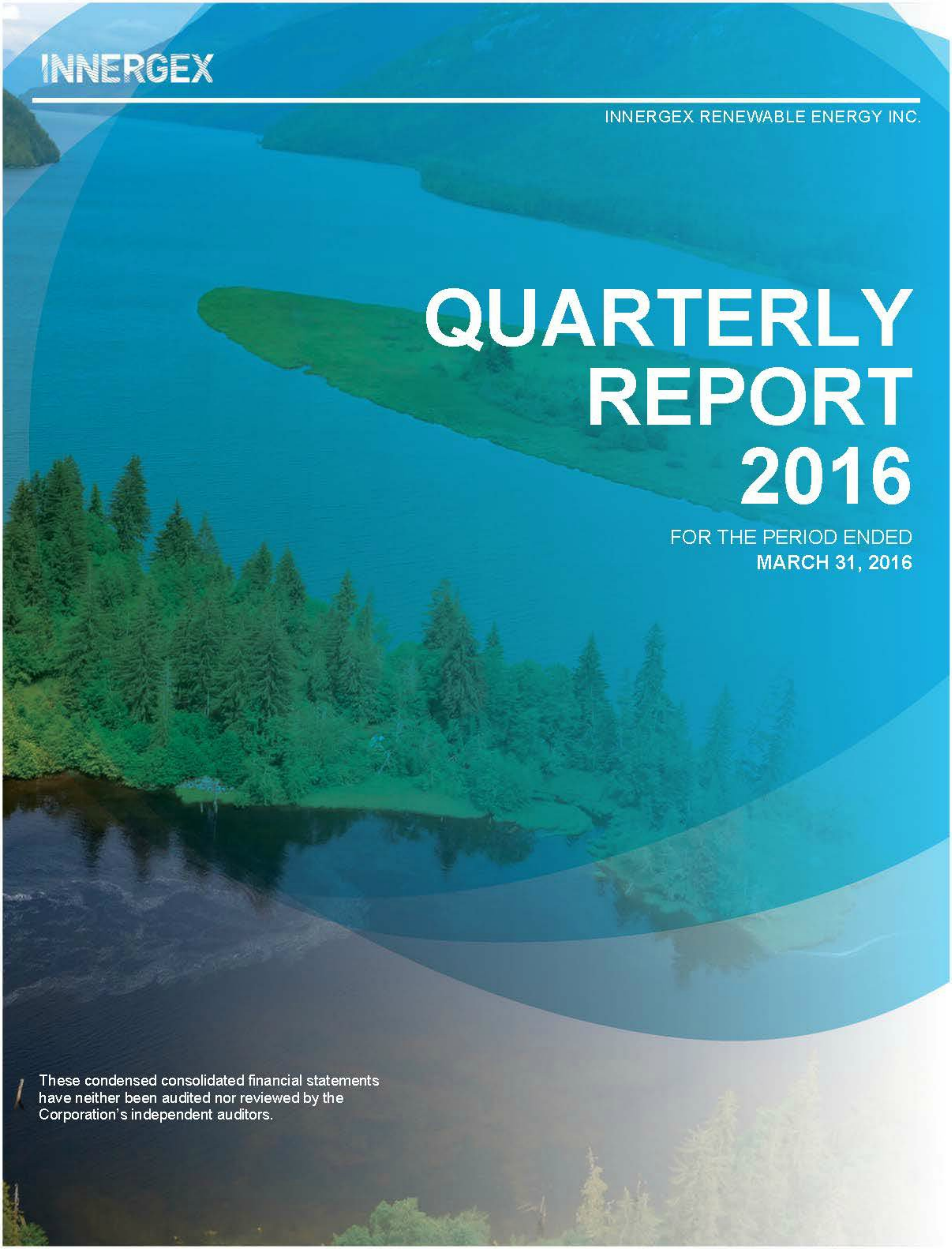

INNERGEX

INNERGEX RENEWABLE ENERGY INC.

QUARTERLY REPORT 2016

FOR THE PERIOD ENDED
MARCH 31, 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 three-month period ended March 31, 2016, and reflects all material events up to May 10, 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-month period ended March 31, 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-month period ended March 31, 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.

Q1 2016 HIGHLIGHTS

- Production was 119% of long-term average ("LTA")
- Revenues increased 8% to $62.5 million compared with the same period last year
- Adjusted EBITDA rose 11% to $47.7 million compared with the same period last year
- Innergex and the Cayoose Creek Indian Band have completed the acquisition of the 16 MW Walden North hydroelectric facility (the "Walden Facility") in British Columbia
- The Corporation signed the final agreements to purchase a portfolio of eight wind power projects located in France
- Innergex has received approval from TSX to renew the normal course issuer bid on its common shares and to commence one on its Preferred Shares

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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 there were no material weaknesses relating to the DC&P and ICFR for the three-month period ended March 31, 2016. During the three-month period ended March 31, 2016, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

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 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; 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; 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
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

Principal Assumptions	Principal Risks and Uncertainties
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) and 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 Projects costs above expectations caused mainly by the performance of counterparties and delays and cost overruns in the design and construction of projects Regulatory and political risk Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness Unexpected maintenance capital expenditures
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
Intention to gain a foothold in target markets internationally The Corporation provides indications of its intention to establish a presence in target markets internationally in the coming years, based on its growth strategy.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs Foreign exchange fluctuations

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, 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 “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) and 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 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:

- 42 facilities in commercial operation (the “Operating Facilities”). Commissioned between 1992 and October 2015, the facilities have a weighted average age of approximately 7.8 years. They sell the generated power under long-term Power Purchase Agreements (“PPA”) that have a weighted average remaining life of 17.7 years (based on gross long-term average production);

- Two projects scheduled to begin commercial operation by the end of 2016 and two projects scheduled to start commercial operations in the first and second quarter of 2017 (all together the “Development Projects”). Construction is ongoing at all four 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.

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

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

	Operating Facilities	Development Projects	Prospective Projects
Hydro			
Gross capacity:	584.2 MW	147.3 MW	1,000.0 MW
Net capacity[1]:	447.1 MW	111.7 MW	900.0 MW
Wind			
Gross capacity:	700.9 MW	150.0 MW	2,450.0 MW
Net capacity[1]:	323.1 MW	75.0 MW	2,300.0 MW
Solar			
Gross capacity:	33.2 MW	-	80.0 MW
Net capacity[1]:	33.2 MW	-	80.0 MW
Total			
Gross capacity:	1318.3 MW	297.3 MW	3,530.0 MW
Net capacity[1]:	803.4 MW	186.7 MW	3,280.0 MW

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

(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, 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 28 hydroelectric facilities, which draw on 25 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	337.4	14%	862.5	35%	754.8	31%	496.0	20%	2,450.9
WIND	269.7	32%	168.5	20%	145.1	17%	262.6	31%	845.9
SOLAR[2]	7.2	19%	12.4	33%	12.5	33%	5.7	15%	37.9
Total	614.4	18%	1,043.4	31%	912.5	27%	764.4	23%	3,334.6

1. The consolidated long-term average production is the annualized LTA for the facilities in operation at May 10, 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)

FIRST QUARTER UPDATE

Summary of operating and financial performance

	Three months ended March 31	
	2016	2015
PRODUCTION		
Power generated (MWh)	664,387	658,427
LTA (MWh)	557,022	542,769
Production as percentage of LTA	119%	121%
STATEMENT OF EARNINGS		
Revenues	62,481	57,727
Adjusted EBITDA	47,681	42,955
Adjusted EBITDA Margin	76.3%	74.4%
Net earnings (loss)	7,197	(37,810)
DIVIDENDS		
Dividend declared per Class A Preferred Share	0.2255	0.3125
Dividend declared per Class C Preferred Share	0.359375	0.359375
Dividend declared per common share	0.160	0.155

For the three-month period ended March 31, 2016, production was 119% of the LTA, due mainly to above-average water flows in British Columbia. Production increased 1%, revenues increased 8% and Adjusted EBITDA increased 11% compared with the same period last year. These increases are attributable mainly to hydro production higher than the LTA in Quebec during the quarter and to the contribution of the BC Tretheway Creek hydroelectric facility, which was partly offset by lower production at some of the other facilities in British Columbia.

The $7.2 million net earnings for the three-month period ended March 31, 2016, compared with a $37.8 million net loss for the same period last year, is attributable mainly to the increase in revenues and to the smaller impact of derivative financial instruments ("Derivatives"), namely a $1.3 million unrealized gain on Derivatives in this period, compared with a $68.0 million realized loss on Derivatives partly offset by an unrealized net gain of $12.0 million, both of which resulting from the closing of the Boulder Creek and Upper Lillooet River financings in the first quarter of 2015.

Impact on net earnings (loss) of Derivatives	Three months ended March 31	
	2016	2015
Net earnings (loss)	7,197	(37,810)
Add (Subtract):		
Unrealized net gain on derivative financial instruments	(1,287)	(11,985)
Realized loss on derivative financial instruments	—	68,047
Income tax expense (recovery of) related to above items	335	(13,583)
Share of unrealized net loss on derivative financial instruments of joint ventures, net of related income tax	540	1,499
	6,785	6,168

Excluding the gains and losses on Derivatives and the related income taxes, the net earnings for the three-month period ended March 31, 2016 would have been $6.8 million, compared with net earnings of $6.2 million for the same period last year. The increase in net earnings during the three-month period is due mainly to the increase in production and the decrease in general and administrative expenses.

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

Payout Ratio

	Trailing 12 months ended March 31	
	2016	2015
Free Cash Flow[1]	77,217	82,212
Payout Ratio[1]	84%	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 March 31, 2016, the dividends on common shares declared by the Corporation corresponded to 84% of Free Cash Flow, compared with 74% for the corresponding prior twelve-month period. This negative impact is due mainly to lower cash flows from operating activities before changes in non-cash operating working capital items and realized losses on derivative financial instruments. The Free Cash Flow is further reduced by greater scheduled debt principal payments, which are partly offset by lower cash flows attributed to the minority interest.

Conversion of the Cumulative Rate Reset Preferred Shares, Series A

On January 15, 2016, and on January 15 every five years thereafter, the holders of Preferred Shares, Series A (the "Series A Shares") are entitled, at their option, to convert all or part of their Series A Shares into Series B, Preferred Shares (the "Series B Shares") of the Corporation, provided certain conditions are met.

On January 7, 2016, the Corporation announced that after considering all election notices received by the conversion deadline of December 31, 2015, and the conversion requirements, the holders of the Series A Shares were not entitled to convert their shares.

Accordingly, 3,400,000 Series A Shares remain listed on the TSX under the symbol INE.PR.A. The dividend rate for the five-year period commencing on January 15, 2016, and extending to but excluding January 15, 2021, will be 3.608% or $0.2255 per share per quarter.

Completion of the Acquisition of the Walden Facility

On February 25, 2016, the Corporation, in partnership with the Cayoose Creek Indian Band, completed the previously announced acquisition from FortisBC of the Walden Facility located in the province of British Columbia, Canada. The Walden Facility is a 16 MW facility commissioned in 1992 and located on private land in Cayoosh Creek near Lillooet and close to several of the Corporation’s other hydroelectric facilities.

Innergex and Cayoose Creek Development Corporation, the economic arm of the Cayoose Creek Indian Band, have formed the Cayoose Creek Limited Partnership, which in turn has acquired the assets that make up the facility. The transaction closed at a total purchase price of $9.2 million.

Acquisition of eight Wind Power Projects in France and a Private Placement of $50.0 million

On March 21, 2016, Innergex announced the potential acquisition of seven operating wind power projects with an installed capacity of 87 MW and another project currently under construction with an installed capacity of 44 MW from a German company, wpd europe GmbH, for a total of 131 MW.

Simultaneously, the Corporation announced a private placement of $50.0 million with three Desjardins Group-affiliated entities.

Innergex completed the acquisition of the seven operating projects and the private placement on April 15, 2016, and should complete the acquisition of the project under construction during the first quarter of 2017, subject to regulatory authorizations and other customary closing conditions.

The purchase price for the eight wind power projects is approximately €98.0 million (equivalent to C$144.4 million), subject to certain adjustments. Of this amount, €65.0 million (or C$95.9 million) was paid for the seven operating projects while €10.0 M (or C$14.7 million) served as a deposit for the project currently under construction. After this last project’s commercial commissioning, the Corporation will pay to the seller an additional amount of €23.0 million (or C$33.8 million), subject to certain adjustments.

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

The non-recourse debt related to the eight projects will remain at the acquired project level. The Corporation has reduced its exposure to exchange rate fluctuations with long-term currency hedging instruments.

Renewal of Normal Course Issuer Bid for Common Shares and Commencement for Preferred Shares

On March 21, 2016, the Corporation announced that it had received approval from the TSX to renew the normal course issuer bid on its common shares ("Common Shares") and to commence a normal course issuer bid on its Cumulative Rate Reset Series A shares ("Series A Shares") and Cumulative Redeemable Fixed Rate Preferred Shares, Series C ("Series C Shares") (collectively, the "Bids").

Under the Bids, the Corporation may purchase for cancellation a maximum of 2,000,000 Common Shares, 68,000 Series A Shares and 40,000 Series C Shares.

The Bids started on March 24, 2016, and will terminate on March 23, 2017.

DEVELOPMENT PROJECTS

At the end of 2015, the Corporation reviewed the total project costs anticipated to achieve the completion of the Development Projects. As at March 31, 2016, the Development Projects' total project costs were as follows:

PROJECTS UNDER CONSTRUCTION	Ownership %	Gross installed capacity (MW)	Expected COD[1]	Gross estimated LTA[2, 3] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[2] ($M)	As at Mar. 31 ($M)	Revenues[2] ($M)	Adjusted EBITDA[2] ($M)
HYDRO (British Columbia)									
Upper Lillooet River	66.7	81.4	2017 [5]	334.0	40	327.1 [4]	237.7 [4]	33.0 [4]	27.5 [4]
Boulder Creek	66.7	25.3	2017 [5]	92.5	40	124.1 [4]	79.8 [4]	9.0 [4]	7.5 [4]
Big Silver Creek	100.0	40.6	2016	139.8	40	206.0	191.9	18.0	15.0
WIND (Quebec)									
Mesgi'g Ugju's'n	50.0	150.0	2016	515.0	20	305.0 [4]	100.6 [4]	55.0 [4]	48.0 [4]
		297.3		1081.3		962.2	610.0	115.0	98.0

1. Commercial operation date.
2. 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.
3. 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.
4. Corresponding to 100% of this facility.
5. 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 project. Commercial operation has been delayed due to the forest fire that forced the interruption of construction activities. 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.

As at the date of this MD&A, the installation of the joint transmission line, the powerhouses, the intakes and the tunnels are well under way. The Boulder Creek powerhouse is mechanically complete and the electrical work will be completed in the next quarter. For the period ended March 31, 2016, and as at the date of this MD&A, the Boulder Creek intake, the Upper Lillooet powerhouse and intake and the intake tunnels at both facilities were the main focus of construction. The Corporation and its contractors continued working throughout the winter, focusing mainly on the tunnels in order to make up for time lost to the 2015 forest fire and geotechnical conditions. The insurance claims process for the fire is ongoing and will take time to complete. To date, interim claims have been processed and paid in an effort to maintain progress. In any case, the Corporation expects to be indemnified and to suffer no significant adverse financial consequences from the forest fire.

Big Silver Creek

Construction of this hydroelectric facility began in June 2014. On June 22, 2015, the Corporation announced the closing of a $197.2 million non-recourse construction and term project financing for this project. As at the date of this MD&A, the civil works for the intake, tunnel, penstock, powerhouse and tailrace have been completed. The turbines and generators have been delivered to the site and their installation is under way, with all second-stage concreting completed. Transmission line construction continued during the quarter for the terrestrial line and the submarine cables. The submarine cable installation was completed during the quarter, as was the terrestrial transmission line on the east side of Harrison Lake. The terrestrial transmission line on the west side of Harrison Lake was approximately 65% complete at the end of the quarter. All major electrical equipment, including the control panels, the switchgear and the station service and intake power transformers, have been delivered to the site and installation is under way. The installation and testing of the electrical equipment outside the Big Silver substation was also completed during the first quarter of 2016.

The end of construction and the commissioning of the Big Silver Creek project are expected for the third quarter of 2016.

Mesgi'g Ugju's'n

Construction of this wind farm began in May 2015. On September 28, 2015, the Corporation and its partner, the 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, the access roads and wind turbines generator ("WTG") areas have been completed. All the WTG foundations have been completed but one, which will be backfilled in May 2016. The work at the electrical substation started at the end of March 2016. Other activities will resume in May 2016. The manufacturing of the turbine components are progressing and the delivery of the wind turbine components at the site are expected to start by June 2016.

The end of construction and the commissioning of the Mesgi'g Ugju's'n wind farm are expected for the end of 2016.

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 expression of interest from Aboriginal businesses for a total of up to 40 megawatts ("MW") of renewable generation from multiple projects in the province of New Brunswick. In Ontario, the government has launched a second phase (LRP II) of the competitive Large Renewable Procurement process. As such, a new Request for Qualifications process will be issued by August 1, 2016, for 930 MW of renewable energy from solar photovoltaic, wind, hydroelectric and bioenergy sources, following engagement with stakeholders, municipalities and indigenous communities. Other Prospective Projects will be available for future requests for proposals yet to be announced or are targeted toward negotiated power purchase agreements with public utilities or other creditworthy counterparties. There is no certainty that any Prospective Project will be realized.

OPERATING RESULTS

Production of electricity for the last quarter was 119% of the LTA production due mainly to the above-average water flows in all markets but Ontario and to the above-average results for the solar regime but was partly offset by below-average results for the wind regime.

Production increased 1%, revenues increased 8% and Adjusted EBITDA increased 11% in 2016. The increase in production is attributable mainly to hydro production in Quebec that was higher than the LTA during the quarter and to the contribution of the BC Tretheway Creek hydroelectric facility, partly offset by lower production at some of the other British Columbia facilities. The higher rate of increase for revenues than for production is explained by the fact that the production increase occurred at facilities that have more lucrative PPAs.

The Corporation's operating results for the three-month period ended March 31, 2016, are compared with the operating results for the same period in 2015.

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

Electricity Production

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

Three months ended March 31	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	134,252	124,170	108%	101.36	119,140	124,170	96%	89.23
Ontario	22,156	24,294	91%	67.17	18,957	24,294	78%	70.05
British Columbia	283,429	179,795	158%	94.18	291,584	165,489	176%	86.22
United States	8,131	7,927	103%	80.14	8,610	7,927	109%	77.35
Subtotal	447,968	336,186	133%	94.74	438,291	321,880	136%	86.16
WIND								
Quebec	208,595	213,605	98%	80.32	213,303	213,605	100%	80.13
SOLAR								
Ontario	7,824	7,231	108%	420.00	6,833	7,284	94%	420.00
Total	664,387	557,022	119%	94.04	658,427	542,769	121%	87.67

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 March 31, 2016, the Corporation's facilities produced 664 GWh of electricity or 119% of the LTA of 557 GWh. Overall, the hydroelectric facilities produced 133% of their LTA, due mainly to above-average water flows in all markets but Ontario. Overall, the wind farms produced 98% of their LTA, due to below-average wind regimes. The Stardale solar farm produced 108% 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 production increase of 1% compared with the same period last year is due mainly to production that was above the LTA of the Quebec hydroelectric facilities during the quarter and to the contribution of the BC Tretheway Creek hydroelectric facility, which began commercial operation in November 2015, partly offset by lower production at some of the other British Columbia facilities.

The overall performance of the Corporation's facilities for the period ended March 31, 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 March 31			
	2016		2015	
Revenues	62,481	100.0%	57,727	100.0%
Operating expenses	9,397	15.0%	9,247	16.0%
General and administrative expenses	3,686	5.9%	4,172	7.2%
Prospective project expenses	1,717	2.7%	1,353	2.3%
Adjusted EBITDA	47,681	76.3%	42,955	74.4%
Finance costs	19,494		16,417	
Other net (revenues) expenses	(174)		68,414	
Depreciation and amortization	19,437		18,797	
Share of loss of joint ventures (note 1)	452		1,144	
Unrealized net gain on derivative financial instruments	(1,287)		(11,985)	
Income tax expense (recovery of)	2,562		(12,022)	
Net earnings (loss)	7,197		(37,810)	
Net earnings (loss) attributable to:				
Owners of the parent	8,333		(29,144)	
Non-controlling interests	(1,136)		(8,666)	
	7,197		(37,810)	
Basic net earnings (loss) per share ($)	0.07		(0.31)	

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 March 31, 2016, the Corporation recorded revenues of $62.5 million, compared with $57.7 million for the three-month period ended March 31, 2015. This 8% increase is attributable mainly to better results from the hydro facilities operating in Quebec, compared with the same period last year, and to the contribution of the Tretheway Creek hydroelectric facility commissioned at the end of 2015, which was partly offset by lower production at some of the other British Columbia facilities. The higher rate of increase for revenues than for production (8% and 1% respectively) is explained by the fact that the production increase occurred at facilities that have more lucrative PPAs.

Expenses

Operating expenses consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes and royalties. For the three-month period ended March 31, 2016, the Corporation recorded operating expenses of $9.4 million ($9.2 million in 2015). This 2% increase is due mainly to the operating costs incurred by the Tretheway Creek hydroelectric facility commissioned in November 2015.

General and administrative expenses consist primarily of salaries, professional fees and office expenses. For the three-month period ended March 31, 2016, general and administrative expenses totalled $3.7 million ($4.2 million in 2015). This 12% decrease stems mainly from resources being devoted to further pursue 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 has chosen to advance and the resources required to do so. For the three-month period ended March 31, 2016, prospective project expenses totalled $1.7 million ($1.4 million in 2015). This 27% increase 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 Ontario and other 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-month period ended March 31, 2016, the Corporation recorded Adjusted EBITDA of $47.7 million, compared with $43.0 million for the same period last year. This 11% increase is due mainly to the increase in production and revenues and to the reduction in general and administrative expenses, partly offset by an increase of prospective project expenses. As a result, the Adjusted EBITDA Margin rose from 74.4% to 76.3%.

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 March 31, 2016, finance costs totalled $19.5 million ($16.4 million in 2015). The increase is due mainly to the lower negative inflation compensation interest on the real-return bonds attributable to lower deflation during the period and to expenses related to the Tretheway Creek facility commissioned in November 2015.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 5.03% as at March 31, 2016 (5.21% as at March 31, 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. For the three-month period ended March 31, 2016, the Corporation recorded other net revenues of $0.2 million (net expenses of $68.4 million in 2015). The change for the period stems from the $68.0 million loss on derivative financial instruments that was realized in 2015 and resulted from the settlement of bond forward contracts upon closing of the Upper Lillooet and Boulder Creek project financing. The Corporation encountered no realized losses during the quarter on its Derivatives.

Depreciation and Amortization

Depreciation and amortization expenses totalled $19.4 million for the three-month period ended March 31, 2016 ($18.8 million in 2015). This increase is attributable mainly to the Tretheway Creek hydroelectric facility commissioned in November 2015.

Share of Loss of Joint Ventures

Share of loss of Joint Ventures of $0.5 million, versus a $1.1 million share of loss of Joint Ventures for the same period in 2015, was recorded by the Corporation for the three-month period ended March 31, 2016. Please refer to the "Investments in Joint Ventures" section for more financial information.

Derivative Financial Instruments

Derivative financial instruments are used by the Corporation to manage its exposure to the risk of rising interest rates on its existing and upcoming debt financing and its exposure to the risk of rising foreign currencies on its equipment purchases (“Derivatives”), thereby protecting the economic value of its projects.

Since October 2014, the Corporation has 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 March 31, 2016, the Corporation recognized an unrealized net gain on derivative financial instruments of $1.3 million, due mainly to the increase in benchmark interest rates since December 31, 2015. For the corresponding period last year, the Corporation recognized an unrealized net gain on Derivatives of $12.0 million, 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 and Upper Lillooet financing in March 2015, which more than offset the unrealized losses on derivative financial instruments resulting from the decrease in benchmark interest rates during the three-month period.

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

For the period ended March 31, 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 March 31, 2016, the Corporation recorded a current income tax expense of $0.6 million ($0.8 million in 2015) and a deferred income tax expense of $1.9 million (income tax recovery of $12.8 million in 2015). The deferred income tax expense is due primarily to the recognition of accounting earnings before income taxes resulting from the regular business activities of the Corporation. The deferred income tax recovery for the same period last year was due mainly to a $68.0 million realized loss on derivative financial instruments resulting from the settlement of the Boulder Creek and Upper Lillooet River bond forward contracts upon closing of the financing for these projects.

Net Earnings (Loss)

Net earnings of $7.2 million (basic and diluted net earnings of $0.07 per share), compared with a net loss of $37.8 million (basic and diluted net loss of $0.31 per share), were recorded by the Corporation in the quarter. The $37.8 million net loss in 2015 was due mainly to the financial impact of the Derivatives recorded in the net earnings (loss) of the Corporation. In the present quarter, no realized gain or loss was recorded by the Corporation on its Derivatives while an unrealized net loss of $1.3 million was recorded, compared with a $68.0 million realized loss on derivative financial instruments in March 2015, partly offset by a $12.0 million unrealized net gain.

Main items explaining the change in net earnings for the three-month period ended March 31, 2016, compared with the net loss for the corresponding period in 2015

Main items – Positive impact	Change	Explanation
Revenues	4,754	Due mainly to the contribution of the Tretheway Creek hydroelectric facility commissioned in November 2015 and to higher production results from the hydro regimes in Quebec.
Other net (revenues) expenses	68,588	Due mainly to the $68.0 million loss on Derivatives realized in 2015 and resulting from the settlement of bond forward contracts upon closing of the Upper Lillooet and Boulder Creek project financing. The Corporation had no realized losses during the quarter.
Main items – Negative impact	**Change**	**Explanation**
Unrealized net gain on derivative financial instruments	10,698	Due mainly to hedge accounting on almost all the Corporation's Derivatives, the impact of the unrealized net (gain) loss on derivative financial instruments is smaller this quarter ($1.3 million net gain in this quarter). For the corresponding period last year, the Corporation recognized a $12.0 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 and Upper Lillooet financing in March 2015.
Deferred income tax expense	14,708	Due mainly to the absence of significant impacts from derivative financial instruments on the Corporation's computation of net earnings (loss) in the first quarter of 2016 as compared to corresponding quarter of 2015, as explained above. The amount of deferred income tax expense in this quarter was determined mainly by the amount of net earnings realized by the Corporation.

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., the Cayoose Creek Limited Partnership entity and their respective general partners. For the period ended March 31, 2016, the Corporation allocated losses of $1.1 million to non-controlling interests (compared with losses of $8.7 million in 2015). The smaller amount of the losses allocated to non-controlling interests in the first quarter of 2016 compared with 2015 is due mainly to the settlement of bond forwards contracts for the Boulder Creek and Upper Lillooet financing in March 2015.

Number of Common Shares Outstanding

Weighted average number of common shares outstanding (000s)	Three months ended March 31	
	2016	2015
Weighted average number of common shares	103,996	100,905
Effect of dilutive elements on common shares[1]	645	463
Diluted weighted average number of common shares	104,641	101,368

1. 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 March 31, 2016, all of the 3,425,684 stock options (all of the 3,425,684 for the three-month period ended March 31, 2015) were dilutive. During the three-month period ended March 31, 2016, none of the 6,666,667 shares that can be issued on conversion of convertible debentures were dilutive (none of the 7,472,113 shares were dilutive in the three-month period ended March 31, 2015).

The Corporation's Equity Securities

As at	May 10, 2016	March 31, 2016	March 31, 2015
Number of common shares	107,972,113	104,006,805	101,061,184
Number of 4.25% convertible debentures	100,000	100,000	—
Number of 5.75% convertible debentures	—	—	79,578
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	3,425,684	3,425,684	3,425,684

As at the date of this MD&A and since March 31, 2016, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 3,906,250 shares (at a price of $12.80 per share) to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex and to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at March 31, 2016, and as has been the case since March 31, 2015, the increase in the number of common shares is attributable mainly to the conversion, at the holders' request, of a portion of the 5.75% convertible debentures into common shares as well as to the DRIP, partly offset by the purchase and cancellation of 1,190,173 shares under the Corporation's normal course issuer bid. The variation in the number of convertible debentures is due to the issuance of 100,000 convertible debentures bearing interest at a rate of 4.25% and the redemption or conversion of convertible debentures bearing interest at a rate of 5.75%.

LIQUIDITY AND CAPITAL RESOURCES

For the three-month period ended March 31, 2016, the Corporation generated cash flows from operating activities of $20.9 million, compared with the use of $47.4 million for the same period last year. During this three-month period, the Corporation generated funds from financing activities of $27.3 million and used funds for investing activities of $51.0 million, mainly to pay for the construction of its Development Projects and the Walden Facility business acquisition. As at March 31, 2016, the Corporation had cash and cash equivalents amounting to $38.0 million, compared with $40.7 million as at December 31, 2015.

Cash Flows from Operating Activities

For the three-month period ended March 31, 2016, cash flows generated by operating activities totalled $20.9 million (compared with $47.4 million used in 2015). The change is attributable mainly to the fact that the Corporation recorded no realized loss on derivative financial instruments in the quarter as opposed to the $68.0 million realized loss on Derivatives recorded in the corresponding quarter of 2015.

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

Cash Flows from Financing Activities

For the three-month period ended March 31, 2016, cash flows generated by financing activities totalled $27.3 million (compared with $145.1 million generated in 2015). The cash flows from the financing activities are attributable mainly to a $44.5 million net increase in long-term debt reflecting mainly additional funds from the Development Projects-level debts and the repayment of long-term debt (including the revolving term credit facility). The amount of cash flows generated by financing activities results from the net increase in long-term debt, partly offset by the payment of dividends by the Corporation.

Use of Financing Proceeds	Three months ended March 31	
	2016	2015
Proceeds from issuance of long-term debt (including revolving term credit facility)	197,487	324,101
Repayment of long-term debt (including revolving term credit facility)	(151,354)	(154,561)
Payment of deferred financing costs	(1,632)	(5,573)
Sub-total: net increase in long-term debt	44,501	163,967
Proceeds from exercise of share options	—	394
Generation of financing proceeds	44,501	164,361
Business acquisitions	(8,330)	—
Realized loss on derivative financial instruments	—	(68,047)
Decrease (increase) of restricted cash and short-term investments	26,354	(41,156)
Net funds invested into the reserve accounts	(35)	(2,892)
Additions to property, plant and equipment	(54,492)	(53,428)
Additions to project development costs	—	(780)
Additions to other long-term assets	(14,528)	(367)
Net use of financing proceeds	(51,031)	(166,670)
Reduction in working capital	(6,530)	(2,309)

During the three-month period ended March 31, 2016, the Corporation borrowed $197.5 million mainly to pay for the construction of the Development Projects, to realize the Walden Facility business acquisition, to make a deposit for the acquisition of the Wind Power Projects in France and to repay long-term debt (including the revolving term credit facility). It also used restricted cash of $26.4 million to continue construction of the Development Projects. During the corresponding period in 2015, the Corporation borrowed $324.1 million mainly to pay for construction of the Upper Lillooet River, Boulder Creek, and Big Silver Creek projects, the pre-construction development of the Mesgi'g Ugju's'n project and the $68.0 million realized loss on derivative financial instruments resulting from the settlement of the Boulder Creek and Upper Lillooet River bond forward contracts. It also increased restricted cash by $41.2 million, as the use of cash to pay for construction costs related to the Tretheway Creek, Boulder Creek and Upper Lillooet projects was more than offset by the addition of $73.4 million corresponding to the unused portion of proceeds of $259.1 million received to date from the Boulder Creek and Upper Lillooet project debts.

Cash Flows from Investing Activities

For the three-month period ended March 31, 2016, cash flows used by investing activities amounted to $51.0 million ($98.6 million in 2015). During this period, the main investing activities that impacted cash flows were: additions to property, plant and equipment accounted for a $54.5 million outflow ($53.4 million outflow in 2015); fluctuations in restricted cash and short-term investments accounted for a $26.4 million inflow ($41.2 million outflow in 2015); additions to other long-term assets accounted for a $14.5 million outflow ($0.4 million outflow in 2015) from a deposit made for the acquisition of the eight wind farms in France; and business acquisitions accounted for an $8.3 million outflow (none in 2015) for the acquisition of the Walden Facility.

Cash and Cash Equivalents

As at March 31, 2016, the Corporation had cash and cash equivalents amounting to $38.0 million ($40.7 million as at December 31, 2015). For the three-month period ended March 31, 2016, cash and cash equivalents decreased by $2.6 million (decreased by $0.8 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 March 31	
	2016	2015
Dividends declared on common shares[1]	16,641	15,664
Dividends declared on common shares ($/share)[1]	0.1600	0.1550
Dividends declared on Series A Preferred Shares	767	1,063
Dividends declared on Series A Preferred Shares ($/share)	0.2255	0.3125
Dividends declared on Series C Preferred Shares	719	719
Dividends declared on Series C Preferred Shares ($/share)	0.359375	0.359375

1. The increase in dividends declared on common shares is mainly attributable to the issuance of 3,566,851 new common shares upon conversion, at the holders' request, of convertible debentures bearing interest at 5.75%.

The following dividends will be paid by the Corporation on July 15, 2016:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
05/10/2016	6/30/2016	7/15/2016	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 March 31, 2016, the Corporation had $3,155 million in total assets, $2,703 million in total liabilities, including $2,258 million in long-term debt, and $451.7 million in shareholders' equity.

Also as at March 31, 2016, the Corporation had a working capital ratio of 2.07:1.00 (2.15:1.00 as at December 31, 2015). In addition to cash and cash equivalents amounting to $38.0 million, the Corporation had restricted cash and short-term investments of $286.4 million and reserve accounts of $42.8 million.

The explanations below highlight the most significant changes in statement of financial position items during the three-month period ended March 31, 2016.

Assets

Highlights of significant changes in total assets during the three-month period ended March 31, 2016

- A $29.0 million net decrease in cash and cash equivalents and restricted cash and short-term investments, due mainly to amounts used to pay for construction costs on the Development Projects, partly offset by drawings on the Development Projects' credit facilities;
- A $44.0 million increase in property, plant and equipment, due mainly to the construction of the Development Projects and the acquisition of the Walden Facility, partly offset by the depreciation for the period;
- A $2.3 million increase in intangible assets, due mainly to the acquisition of the Walden Facility, partly offset by the amortization for the period; and
- A $13.6 million increase in other long term assets, due mainly to a deposit in view of the acquisition of Wind Projects in France.

Working Capital Items

Working capital was positive at $188.3 million, as at March 31, 2016, with a working capital ratio of 2.07:1.00. 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 $2.6 million decrease in cash and cash equivalents, a $26.4 million decrease in restricted cash and short-term investments and a $3.9 million decrease in accounts receivable, which are explained separately below. The impact of these items on the working capital ratio was partly offset by a $8.8 million decrease in accounts payable, also explained separately below.

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 March 31, 2016, the Corporation had drawn $164.9 million and US$13.9 million as cash advances, while $90.0 million had been used for issuing letters of credit.

Restricted cash and short-term investments amounted to $286.4 million as at March 31, 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 $33.1 million between December 31, 2015, and March 31, 2016, due mainly to commodity taxes received from construction of the Development Projects.

Accounts payable and other payables from December 31, 2015, to March 31, 2016, decreased from the amount of $95.5 million to $86.6 million, due mainly to payments of interest payable and to payments of accounts payable by Big Silver, partly offset by additional construction activity at the Boulder Creek, Upper Lillooet River and the Mesgi'g Ugju's'n projects.

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 $41.7 million in long-term reserve accounts as at March 31, 2016, compared with $41.5 million as at December 31, 2015. The increase is due to mandatory investments in reserves.

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. The Corporation had $2,218 million in property, plant and equipment as at March 31, 2016, compared with $2,174 million as at December 31, 2015. The increase stems mainly from the construction of the Development Projects and the purchase of the Walden Facility, 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 $474.6 million in intangible assets as at March 31, 2016, compared with $472.3 million as at December 31, 2015. The increase is due mainly to the acquisition of the Walden Facility, 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 March 31, 2016, the Corporation had $8.7 million in investments in joint ventures, compared with $9.3 million as at December 31, 2015. This $0.6 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 $0.5 million net loss related to the Umbata Falls Facility. The other portion of $0.5 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 the risk of rising foreign currencies on its equipment purchases. 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 $627.7 million as at March 31, 2016.

Overall, Derivatives had a net negative value of $79.5 million at March 31, 2016 (negative $67.7 million at December 31, 2015). The increase is due mainly to the drop in benchmark interest rates since the end of 2015. 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 March 31, 2016, long-term debt totalled $2,258 million ($2,215 million as at December 31, 2015). The $42.9 million increase results mainly from additional amounts drawn on Innergex's credit facility, from Stardale's long-term debt increase on its borrowing and from additional drawings on Upper Lillooet's financing, 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.

As at March 31, 2016, 99% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (95% as at March 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.

Shareholders' Equity

As at March 31, 2016, the Corporation's shareholders' equity totalled $451.7 million, including $19.9 million of non-controlling interests, compared with $471.6 million, including $21.9 million of non-controlling interests, as at December 31, 2015. This $19.8 million decrease in total shareholders' equity is attributable mainly to the realization of $7.2 million in net earnings, partly offset by $18.1 million in dividends declared on common and preferred shares and to the recognition of other items of comprehensive loss of $9.7 million.

For the three-month period ended March 31, 2016, the Corporation recognized in the other items of comprehensive loss a $12.1 million unrealized net loss on derivative financial instruments due mainly to the decrease in benchmark interest rates since December 31, 2015.

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

Off-Balance-Sheet Arrangements

As at March 31, 2016, the Corporation had issued letters of credit totaling $141.7 million to meet its obligations under its various PPAs and other agreements. Of this amount, $90.0 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.

Free Cash Flow and Payout Ratio calculation	Trailing 12 months ended March 31	
	2016	2015
Cash flows from operating activities	72,872	45,580
Add (Subtract) the following items:		
Changes in non-cash operating working capital items	(6,626)	7,058
Maintenance capital expenditures net of proceeds from disposals	(3,404)	(2,871)
Scheduled debt principal payments	(32,755)	(30,294)
Free Cash Flow attributed to non-controlling interests[1]	(2,825)	(9,162)
Dividends declared on Preferred shares	(6,829)	(7,125)
Cash receipt for wheeling services to be provided by the Harrison Hydro L.P. to other facilities[2]	3,327	2,092
Adjust for the following elements:		
Transaction costs related to realized acquisitions	1,947	521
Realized losses on derivative financial instruments	51,510	76,413
Free Cash Flow	77,217	82,212
Dividends declared on common shares	64,623	60,834
Payout Ratio - before the impact of the DRIP	84%	74%
Dividends declared on common shares and paid in cash[3]	60,074	49,689
Payout Ratio - after the impact of the DRIP	78%	60%

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 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 three-month period ended March 31, 2016, the Corporation generated Free Cash Flow of $77.2 million, compared with $82.2 million for the same period last year. This decrease is due mainly to lower cash flows from operating activities before changes in non-cash operating working capital items and realized losses on derivative financial instruments. The Free Cash Flow was further reduced by greater scheduled debt principal payments, which were partly offset by lower cash flows attributed to the minority interest.

Payout Ratio

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

For the trailing twelve-month period ending on ended March 31, 2016, the dividends on common shares declared by the Corporation corresponded to 84% 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 explained above and the higher number of common shares outstanding by virtue of the conversion, at the holders' request, of a portion of the 5.75% convertible debentures into common shares and by virtue of the DRIP, partly offset by the purchase and cancellation of 1,190,173 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 ending on March 31, 2016, the Corporation incurred prospective project expenses of $8.4 million, compared with $6.0 million for the corresponding prior period. This 40% 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 8% points lower for the twelve-month period ending on March 31, 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 four 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 these projects and the additional equity provided by the DRIP.

OUTLOOK FOR 2017

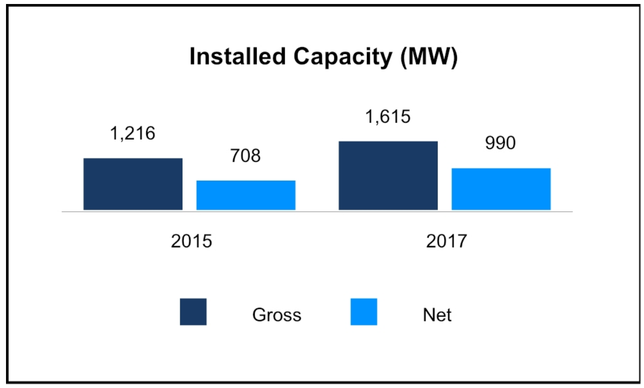
The Corporation makes certain projections to provide readers with an indication of its business activities and operating performance once the four existing Development Projects have been commissioned. These projections also include the data for the Walden Facility and the seven French wind power projects, which were acquired by the Corporation in the first and second quarters of 2016, respectively. Please refer to the "Development Projects" section for more information on these development projects and to the "First Quarter Update" for more information on the business acquisitions. These projections do not take into account possible acquisitions, divestments or additional Development Projects following the award of any new power purchase agreements.

Once the four Development Projects have been commissioned and following the acquisition of Walden and the seven French wind power projects, the Corporation expects its annualized consolidated LTA production to increase from 3,130 GWh at the end of 2015 to 4,418 GWh in 2017, which corresponds to a 41% increase.

(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 four Development Projects have been commissioned and following the acquisition of Walden and the seven French wind power projects, the Corporation expects its net installed capacity to increase from 708 MW (gross 1,216 MW) at the end of the year 2015 to 990 MW (gross 1,615 MW) in 2017, corresponding to a 40% 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 four Development Projects have been commissioned and following the acquisition of Walden and the seven French wind power projects, 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

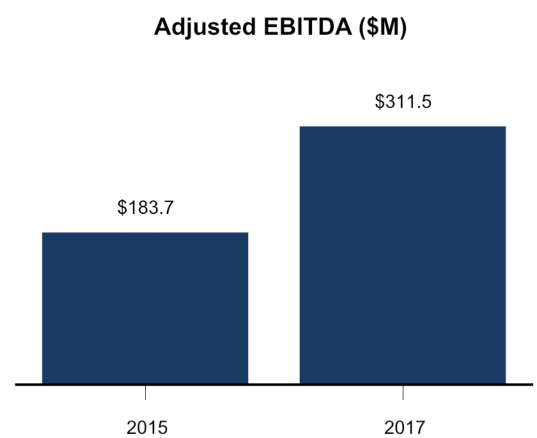
Annualized Consolidated LTA Production (GWh)

	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

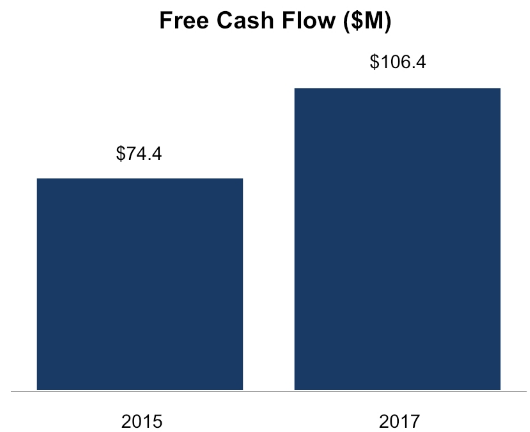
A key performance indicator for the Corporation is Adjusted EBITDA generation. Once the four Development Projects have been commissioned and following the acquisition of Walden and the seven French wind power projects, the Corporation expects to generate annualized Adjusted EBITDA starting in 2017 of 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.

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 four Development Projects have been commissioned and following the acquisition of Walden and the seven French wind power projects, the Corporation expects to generate Free Cash Flow in 2017 of approximately $106.4 million, compared with $74.4 million in 2015. This represents an annual compound growth rate of approximately 20% 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 $32.0 million ($106.4 million compared to $74.4 million), compared with the information published as at December 31, 2015, is due mainly to the acquisition of the seven French wind farm projects.



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 March 31, 2016, the Corporation had interests in 27 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the three-month period ended March 31, 2016, the revenues generated by the Horseshoe Bend hydroelectric facility in the United States totalled $0.7 million ($0.7 million in 2015), corresponding to a contribution of 1.0% (1.2% in 2015) to the Corporation's consolidated revenues.

Operating Segments

As at March 31, 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 March 31, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	447,968	208,595	7,824	—	664,387
Revenues	42,440	16,755	3,286	—	62,481
Expenses:					
Operating expenses	7,110	2,130	157	—	9,397
General and administrative expenses	1,952	948	40	746	3,686
Prospective project expenses	—	—	—	1,717	1,717
Adjusted EBITDA	33,378	13,677	3,089	(2,463)	47,681
Three months ended March 31, 2015					
Power generated (MWh)	438,291	213,303	6,833	—	658,427
Revenues	37,764	17,093	2,870	—	57,727
Expenses:					
Operating expenses	6,799	2,235	213	—	9,247
General and administrative expenses	2,398	934	43	797	4,172
Prospective project expenses	—	—	—	1,353	1,353
Adjusted EBITDA	28,567	13,924	2,614	(2,150)	42,955

FINANCIAL POSITION As at March 31, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	—	—	—	8,269
Total assets	1,794,531	329,840	113,276	917,396	3,155,043
Total liabilities	1,337,183	207,413	119,927	1,038,805	2,703,328
Acquisition of property, plant and equipment during the period	2,675	140	—	55,311	58,126
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 March 31, 2016, this segment produced 133% of the LTA and generated revenues of $42.4 million, compared with a production at 136% of the LTA and revenues of $37.8 million for the same period last year. The revenue increase in this segment is due mainly to production above the long-term average of the hydroelectric facilities in Quebec during the quarter and to the contribution of the Tretheway Creek hydroelectric facility, which began commercial operation in November 2015, partly offset by lower production at some of the other facilities in British Columbia.

The decrease in total assets since December 31, 2015, is attributable mainly to the depreciation of property, plant and equipment and amortization of intangible assets, partly offset by the addition of the Walden Facility.

The decrease in total liabilities since December 31, 2015, is attributable mainly to the scheduled repayment of long-term debt.

Wind Power Generation Segment

For the three-month period ended March 31, 2016, this segment produced 98% of the LTA and generated revenues of $16.8 million, compared with production at 100% of the LTA and revenues of $17.1 million for the same period last year. The production decrease and corresponding revenue decrease are due mainly to lower wind regimes in Quebec.

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

The decrease in total liabilities since December 31, 2015, is attributable mainly to the scheduled repayment of long-term debt.

Solar Power Generation Segment

For the three-month period ended March 31, 2016, this segment produced 108% of the LTA and generated revenues of $3.3 million, compared with production at 94% of the LTA and revenues of $2.9 million for the same period last year. The increase in production and revenues 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 long-term debt increase on its borrowing, partly offset by the scheduled repayment.

Site Development Segment

For the quarter ended March 31, 2016, site development expenses were $2.5 million, compared with $2.2 million 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 increase in total assets since December 31, 2015, is attributable mainly to payments made for costs incurred for the construction of the Development Projects and a deposit made by the Corporation for its business acquisition in France, partly offset by a decrease in restricted cash, which was used to pay for the construction of the Development Projects.

Since December 31, 2015, the increase in total liabilities is mainly due to 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)	Mar. 31, 2016	Dec. 31, 2015	Sept. 30, 2015	June 30, 2015
Power generated (MWh)	664,387	647,062	777,975	904,172
Revenues	62.5	56.3	62.7	70.2
Adjusted EBITDA	47.7	38.8	48.6	53.4
Realized and unrealized net gain (loss) on derivative financial instruments	1.3	2.0	(2.7)	18.6
Impairment of project development costs	—	(51.7)	—	—
Net earnings (loss)	7.2	(34.4)	1.3	22.5
Net earnings (loss) attributable to owners of the parent	8.3	(30.6)	5.8	22.8
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.07	(0.31)	0.04	0.21
Dividends declared on preferred shares	1.5	1.8	1.8	1.8
Dividends declared on common shares	16.6	16.1	16.2	15.7
Dividends declared on common shares, $ per share	0.160	0.155	0.155	0.155

(in millions of dollars, unless otherwise stated)	Three-months ended Mar. 31, 2015	Dec. 31, 2014	Sept. 30, 2014	June 30, 2014
Power generated (MWh)	658,427	819,903	826,617	898,722
Revenues	57.7	68.2	66.4	69.6
Adjusted EBITDA	43.0	48.7	51.7	53.8
Realized and unrealized net loss on derivative financial instruments	(56.0)	(49.6)	(15.3)	(29.1)
Impairment of project development costs	—	—	—	—
Net loss	(37.8)	(27.6)	(4.5)	(14.2)
Net loss attributable to owners of the parent	(29.1)	(18.9)	(0.7)	(7.8)
Net loss attributable to owners of the parent ($ per share – basic and diluted)	(0.31)	(0.21)	(0.02)	(0.10)
Dividends declared on preferred shares	1.8	1.8	1.8	1.8
Dividends declared on common shares	15.7	15.1	15.1	15.0
Dividends declared on common shares, $ per share	0.155	0.150	0.150	0.150

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 73% 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 changes in 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 and Payout Ratio. Furthermore, the Corporation recorded an amount of impairment on project development costs, which had an impact on the net loss registered in the fourth quarter of 2015.

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 March 31	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	28,109	16,927	166%	84.94	22,102	16,927	131%	84.77
Viger-Denonville	21,767	20,300	107%	149.47	25,451	20,300	125%	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 March 31	
	2016	2015
Revenues	2,388	1,873
Operating and general and administrative expenses	235	175
Adjusted EBITDA	2,153	1,698
Finance costs	631	593
Other net revenues	(8)	(8)
Depreciation and amortization	1,004	1,008
Unrealized net loss on derivative financial instruments	1,448	1,999
Net loss and comprehensive loss	(922)	(1,894)

For the three-month period ended March 31, 2016, production was 166% of the LTA, due mainly to above-average water flows. The increase in Adjusted EBITDA is due mainly to higher levels of production in comparison to the same period last year. The net loss for both periods is attributable to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates during each period, which was reduced in the present quarter by an increase in revenues.

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

As at	March 31, 2016	December 31, 2015
Current assets	3,338	2,223
Non-current assets	67,478	68,467
	70,816	70,690
Current liabilities	3,673	3,062
Non-current liabilities	49,289	48,852
Partners' equity	17,854	18,776
	70,816	70,690

As at March 31, 2016, the reduction in partners' equity stems from the net loss of $0.9 million generated for the three-month period. The increase in current liabilities and corresponding increase in non-current liabilities result from the unrealized net loss on a derivative financial instrument arising from a decrease in the benchmark interest rate. In order to manage its exposure to the risk of increasing interest rates on its debt financing, Umbata Falls, L.P. uses a derivative financial instrument and does not own or issue any derivative financial instruments for speculation purposes. An amortizing interest-rate swap totaling $44.0 million used to hedge the interest rate on the Umbata Falls loan had a net negative value of $9.5 million at March 31, 2016 (negative $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 March 31	
	2016	2015
Revenues	3,254	3,796
Operating and general and administrative expenses	506	489
Adjusted EBITDA	2,748	3,307
Finance costs	929	921
Other net revenues	(3)	(18)
Depreciation and amortization	731	730
Unrealized net (gain) loss on derivative financial instruments	(123)	2,107
Net earnings (loss)	1,214	(433)
Other comprehensive loss	(1,453)	—
Total other comprehensive loss	(239)	(433)

For the three-month period ended March 31, 2016, production was 107% of the LTA, due mainly to above-average wind regimes. The decrease in revenues and Adjusted EBITDA is due mainly to lower production levels than for the same period 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.

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

As at	March 31, 2016	December 31, 2015
Current assets	2,099	2,426
Non-current assets	58,793	59,518
	60,892	61,944
Current liabilities	4,528	4,500
Non-current liabilities	57,600	57,191
(Deficit) Partners' equity	(1,236)	253
	60,892	61,944

As at March 31, 2016, the reduction in partners' equity stems mainly from a distribution of $1.3 million and by the recognition of an Other comprehensive loss for the three-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 $54.3 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $7.5 million at March 31, 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 are recorded in other long-term liabilities in Innergex's Statements of Financial Position.

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.

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

Completion of the Acquisition of seven Wind Power Projects in France and a Private Placement of $50 million

On April 15, 2016, the Corporation completed the acquisition of a portfolio of seven Wind Power Projects located in France. Simultaneously, the Corporation announced a private placement of $50.0 million with three Desjardins Group-affiliated entities, which have collectively subscribed to 3,906,250 common shares of the Corporation .

CONSOLIDATED STATEMENTS OF EARNINGS

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

		Three months ended March 31	
		2016	2015
	Notes		
Revenues		62,481	57,727
Expenses			
Operating	4	9,397	9,247
General and administrative		3,686	4,172
Prospective projects		1,717	1,353
Earnings before finance costs, income taxes, depreciation, amortization, other net (revenues) expenses, share of loss of joint ventures and unrealized net gain on derivative financial instruments		47,681	42,955
Finance costs	5	19,494	16,417
Other net (revenues) expenses	6	(174)	68,414
Earnings (loss) before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net gain on derivative financial instruments		28,361	(41,876)
Depreciation	4, 8	13,783	13,257
Amortization	4	5,654	5,540
Share of loss of joint ventures		452	1,144
Unrealized net gain on derivative financial instruments		(1,287)	(11,985)
Earnings (loss) before income taxes		9,759	(49,832)
Income tax expense (recovery of)			
Current		627	751
Deferred		1,935	(12,773)
		2,562	(12,022)
Net earnings (loss)		7,197	(37,810)
Net earnings (loss) attributable to:			
Owners of the parent		8,333	(29,144)
Non-controlling interests		(1,136)	(8,666)
		7,197	(37,810)
Weighted average number of common shares outstanding (in 000s)	7	103,996	100,905
Basic net earnings (loss) per share ($)	7	0.07	(0.31)
Diluted weighted average number of common shares outstanding (in 000s)	7	104,641	101,368
Diluted net earnings (loss) per share ($)	7	0.07	(0.31)

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 March 31	
		2016	2015
	Notes		
Net earnings (loss)		7,197	(37,810)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:			
Foreign exchange (loss) gain on translation of self-sustaining foreign subsidiaries		(580)	738
Related deferred tax		88	(97)
Foreign exchange gain (loss) on the designated portion of the US dollar denominated debt used as hedge on the investment in self-sustaining foreign subsidiaries		666	(753)
Related deferred tax		(88)	99
Change in fair value of hedging instruments		(12,115)	(1,795)
Related deferred tax		3,205	473
Share of non-controlling interests in change in fair value of hedging instruments		(939)	—
Related deferred tax		84	—
Other comprehensive loss		(9,679)	(1,335)
Total comprehensive loss		(2,482)	(39,145)
Other comprehensive loss attributable to:			
Owners of the parent		(8,824)	(1,335)
Non-controlling interests		(855)	—
		(9,679)	(1,335)
Total comprehensive loss attributable to:			
Owners of the parent		(491)	(30,479)
Non-controlling interests		(1,991)	(8,666)
		(2,482)	(39,145)

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	March 31, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents		38,046	40,663
Restricted cash and short-term investments		286,366	312,720
Accounts receivable		33,126	37,073
Reserve accounts		1,091	1,315
Income tax receivable		11	4
Derivative financial instruments		1,132	1,209
Prepaid and others		5,192	4,363
		364,964	397,347
Non-current assets			
Reserve accounts		41,720	41,521
Property, plant and equipment	8	2,218,237	2,174,222
Intangible assets		474,600	472,271
Investments in joint ventures		8,748	9,327
Derivative financial instruments		2,525	2,768
Deferred tax assets		15,123	15,356
Goodwill		8,269	8,269
Other long-term assets		20,857	7,222
		3,155,043	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	March 31, 2016	December 31, 2015
Liabilities			
Current liabilities			
Dividends payable to shareholders		18,126	17,892
Accounts payable and other payables		86,632	95,466
Income tax payable		1,109	1,234
Derivative financial instruments		15,019	15,337
Current portion of long-term debt		55,439	54,995
Current portion of other liabilities		308	246
		176,633	185,170
Non-current liabilities			
Derivative financial instruments		68,113	56,348
Long-term debt	9	2,202,854	2,160,438
Other liabilities		14,901	13,429
Liability portion of convertible debentures		93,780	93,430
Deferred tax liabilities		147,046	147,931
		2,703,327	2,656,746
Shareholders' equity			
Common share capital		109,267	108,541
Contributed surplus from reduction of capital on common shares		775,413	775,413
Preferred shares		131,069	131,069
Share-based payment		2,194	2,174
Equity portion of convertible debentures		1,877	1,877
Deficit		(577,641)	(567,848)
Accumulated other comprehensive loss		(10,400)	(1,576)
Equity attributable to owners		431,779	449,650
Non-controlling interests		19,937	21,907
Total shareholders' equity		451,716	471,557
		3,155,043	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										
For the three-month period ended March 31, 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)							8,333		8,333	(1,136)	7,197
Other items of comprehensive loss								(8,824)	(8,824)	(855)	(9,679)
Total comprehensive income (loss)	—	—	—	—	—	—	8,333	(8,824)	(491)	(1,991)	(2,482)
Common shares issued through dividend reinvestment plan	68	726							726		726
Share-based payment					20				20		20
Investments from non-controlling interests									—	21	21
Dividends declared on common shares							(16,641)		(16,641)		(16,641)
Dividends declared on preferred shares							(1,485)		(1,485)		(1,485)
Balance March 31, 2016	104,006	109,267	775,413	131,069	2,194	1,877	(577,641)	(10,400)	431,779	19,937	451,716

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										
For the three-month period ended March 31, 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	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							(29,144)		(29,144)	(8,666)	(37,810)
Other items of comprehensive loss								(1,335)	(1,335)		(1,335)
Total comprehensive loss	—	—	—	—	—	—	(29,144)	(1,335)	(30,479)	(8,666)	(39,145)
Common shares issued through dividend reinvestment plan	258	2,865							2,865		2,865
Share-based payment					53				53		53
Share options exercised	45	462			(68)				394		394
Convertible debenture converted in common shares	86	922				(21)			901		901
Distributions to non-controlling interests									—	(5,249)	(5,249)
Dividends declared on common shares							(15,664)		(15,664)		(15,664)
Dividends declared on preferred shares							(1,781)		(1,781)		(1,781)
Balance March 31, 2015	101,061	66,473	784,482	131,069	2,035	1,319	(512,925)	(1,350)	471,103	33,496	504,599

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)

		Three months ended March 31	
		2016	2015
	Notes		
Operating activities			
Net earnings (loss)		7,197	(37,810)
Items not affecting cash:			
Depreciation	8	13,783	13,257
Amortization		5,654	5,540
Share of loss of joint ventures		452	1,144
Unrealized net gain on derivative financial instruments		(1,287)	(11,985)
Inflation compensation interest	5	(893)	(3,642)
Amortization of financing fees	5	250	191
Accretion of long-term debt and convertible debentures	5	462	131
Accretion expenses on other liabilities	5	96	159
Share-based payment		21	53
Deferred income taxes		1,935	(12,773)
Effect of exchange rate fluctuations		(811)	600
Interest on long-term debt and convertible debentures	5	19,398	19,402
Interest paid		(20,065)	(18,233)
Distributions received from joint ventures		625	1,000
Current income tax expense		627	751
Net income taxes paid		(731)	(1,036)
		26,713	(43,251)
Changes in non-cash operating working capital items	10	(5,779)	(4,131)
		20,934	(47,382)
Financing activities			
Dividends paid on common shares		(15,385)	(12,236)
Dividends paid on preferred shares		(1,781)	(1,781)
Distributions to non-controlling interests		—	(5,249)
Increase of long-term debt		197,487	324,101
Repayment of long-term debt		(151,354)	(154,561)
Payment of deferred financing costs		(1,632)	(5,573)
Proceeds from exercise of share options		—	394
		27,335	145,095

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)

		Three months ended March 31	
		2016	2015
	Notes		
Investing activities			
Business acquisition	3	(8,330)	—
Decrease (increase) of restricted cash and short-term investments		26,354	(41,156)
Net funds invested into the reserve accounts		(35)	(2,892)
Additions to property, plant and equipment		(54,492)	(53,428)
Additions to project development costs		—	(780)
Additions to other long-term assets		(14,528)	(367)
		(51,031)	(98,623)
Effects of exchange rate changes on cash and cash equivalents		145	151
Net decrease in cash and cash equivalents		(2,617)	(759)
Cash and cash equivalents, beginning of period		40,663	54,609
Cash and cash equivalents, end of period		38,046	53,850
Cash and cash equivalents is comprised of:			
Cash		21,155	37,049
Short-term investments		16,891	16,801
		38,046	53,850

Additional information is presented in Note 10.

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 May 10, 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.

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.

3. BUSINESS ACQUISITION

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.

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

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 three-month period ended March 31, 2016 would have been $62,594 and $7,147 respectively.

The amounts of revenues and net loss of Cayoose LP since February 25, 2016 included in the consolidated statement of earnings are $64 and $47 respectively for the 36 days ended March 31, 2016.

4. OPERATING EXPENSES

	Three months ended March 31	
	2016	2015
Salaries	1,113	973
Insurance	662	653
Operation and maintenance	3,571	3,785
Property taxes and royalties	4,051	3,836
	9,397	9,247

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

5. FINANCE COSTS

	Three months ended March 31	
	2016	2015
Interest on long-term debt and on convertible debentures	19,398	19,402
Inflation compensation interest	(893)	(3,642)
Amortization of financing fees	250	191
Accretion of long-term debt and convertible debentures	462	131
Accretion expenses on other liabilities	96	159
Others	181	176
	19,494	16,417

6. OTHER NET (REVENUES) EXPENSES

	Three months ended March 31	
	2016	2015
Transaction costs	911	—
Realized loss on derivative financial instruments	—	68,047
Realized (gain) loss on foreign exchange	(510)	661
Other net revenues	(290)	(294)
Recovery of loan impairment	(285)	—
	(174)	68,414

7. EARNINGS PER SHARE

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

	Three months ended March 31	
	2016	2015
Net earnings (loss) attributable to owners of the parent	8,333	(29,144)
Dividends declared on preferred shares	(1,485)	(1,781)
Net earnings (loss) available to common shareholders	6,848	(30,925)
Weighted average number of common shares (in 000s)	103,996	100,905
Basic net earnings (loss) per share ($)	0.07	(0.31)
Weighted average number of common shares (in 000s)	103,996	100,905
Effect of dilutive elements on common shares (in 000s) (a)	645	463
Diluted weighted average number of common shares (in 000s)	104,641	101,368
Diluted net earnings (loss) per share ($) (b)	0.07	(0.31)

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 March 31, 2016, all of the 3,425,684 stock options (all of the 3,425,684 for the three-month period ended March 31, 2015) were dilutive.

During the three-month period ended March 31, 2016, none of the 6,666,667 shares that can be issued on conversion of convertible debentures were dilutive (none of the 7,472,113 shares were dilutive in the three-month period ended March 31, 2015).

b. During the three-month period ended March 31, 2015, all of the 3,425,684 stock options were excluded from the calculation of diluted net loss per share as it was anti-dilutive due to a net loss available to common shareholders.

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

8. 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	—	845	71	—	55,199	225	56,340
Business acquisition (Note 3)	286	1,500	—	—	—	—	1,786
Other changes	—	—	—	—	—	(263)	(263)
Net foreign exchange differences	(10)	(499)	—	—	—	(1)	(510)
As at March 31, 2016	2,899	1,428,871	372,109	124,274	586,790	9,155	2,524,098
Accumulated depreciation							
As at January 1, 2016	—	(164,117)	(100,307)	(21,820)	—	(6,279)	(292,523)
Depreciation	—	(7,328)	(4,439)	(1,489)	—	(527)	(13,783)
Other changes	—	—	—	—	—	263	263
Net foreign exchange differences	—	176	—	—	—	6	182
As at March 31, 2016	—	(171,269)	(104,746)	(23,309)	—	(6,537)	(305,861)
Carrying amount as at March 31, 2016	2,899	1,257,602	267,363	100,965	586,790	2,618	2,218,237

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 $10,486 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 $2,868 ($2,622 as at December 31, 2015).

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

9. 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.

10. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Three months ended March 31	
	2016	2015
Accounts receivable and income tax receivable	4,008	(4,251)
Prepaid and others	(835)	(791)
Accounts payable and other payables and income tax liabilities	(8,952)	(5,249)
	(5,779)	(10,291)

b. Additional information

	Three months ended March 31	
	2016	2015
Interest paid (including $10,268 capitalized interest ($1,745 in 2015))	30,333	19,978
Non-cash transactions		
in unpaid property, plant and equipment	1,755	7,803
in unpaid development costs	—	(141)
in common shares issued through the conversion of convertible debentures	—	(922)
in common shares issued through share options exercised	—	(68)
in common shares issued through dividend reinvestment plan	(726)	(2,865)
loans to partners in exchange of non-controlling interests in subsidiaries	(21)	—

11. SEGMENT INFORMATION

Geographic segments

The Corporation owns interests in 27 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the three-month period ended March 31, 2016, revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $652 ($666 in 2015), representing a contribution of 1.0% (1.2% in 2015) to the Corporation's consolidated revenues for these periods.

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 loss of joint ventures and unrealized net gain on derivative 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 March 31, 2016 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	42,440	16,755	3,286	—	62,481
Expenses:					
Operating	7,110	2,130	157	—	9,397
General and administrative	1,952	948	40	746	3,686
Prospective projects	—	—	—	1,717	1,717
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of loss of joint ventures and unrealized net gain on derivative financial instruments	33,378	13,677	3,089	(2,463)	47,681
Finance costs					19,494
Other net revenues					(173)
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net gain on derivative financial instruments					28,360
Depreciation					13,783
Amortization					5,654
Share of loss of joint ventures					452
Unrealized net gain on derivative financial instruments					(1,287)
Earnings before income taxes					9,758

As at March 31, 2016					
Goodwill	8,269	—	—	—	8,269
Total assets	1,794,531	329,840	113,276	917,396	3,155,043
Total liabilities	1,337,183	207,413	119,927	1,038,805	2,703,328
Acquisition of property, plant and equipment during the period	2,675	140	—	55,311	58,126

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

Three months ended March 31, 2015 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	37,764	17,093	2,870	—	57,727
Expenses:					
Operating	6,799	2,235	213	—	9,247
General and administrative	2,398	934	43	797	4,172
Prospective projects	—	—	—	1,353	1,353
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of loss of joint ventures and unrealized net gain on derivative financial instruments	28,567	13,924	2,614	(2,150)	42,955
Finance costs					16,417
Other net expenses					68,414
Earnings (loss) before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net gain on derivative financial instruments					(41,876)
Depreciation					13,257
Amortization					5,540
Share of loss of joint ventures					1,144
Unrealized net gain on derivative financial instruments					(11,985)
Loss before income taxes					(49,832)

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)

12. 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 ($)
05/10/2016	06/30/2016	07/15/2016	0.1600	0.2255	0.359375

b. Acquisition of Wind Projects in France

On April 15, 2016, the Corporation finalized the acquisition of a portfolio of 7 wind power projects located in France. Simultaneously, the Corporation announced that three Desjardins Group affiliated entities have collectively subscribed to a private placement of 3,906,250 common shares of the Corporation for gross proceeds of $50,000.

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

Computershare Investor Services Inc.
1500 Robert-Bourassa Blvd, Suite 700, Montreal, Quebec, H3A 3S8
Telephone: 1 800 564-6253 or 514 982-7555
Email: service@computershare.com

Dividend Reinvestment Plan

Innergex Renewable Energy Inc. implemented a Dividend Reinvestment Plan (DRIP) for its common shareholders, which enables eligible holders of common shares to acquire additional common shares of the Corporation by reinvesting all or part of their cash dividends. For more information about the Corporation's DRIP, please visit our Website or contact the DRIP administrator, Computershare Trust Company of Canada.

Independent Auditor

Deloitte LLP

Investor Relations

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

Jean Perron CPA, CA
Chief Financial Officer

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