INNERGEX

Renewable Energy.
Sustainable Development.

QUARTERLY REPORT 2014

FOR THE PERIOD ENDED JUNE 30, 2014

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

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

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

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

INTRODUCTION

This Management's Discussion and Analysis ("MD&A") is a discussion of the operating results, cash flows and financial position of Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") for the six-month period ended June 30, 2014, and reflects all material events up to August 7, 2014, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the unaudited condensed consolidated financial statements and the accompanying notes for the six-month period ended June 30, 2014, and with the Corporation's *Financial Review* at December 31, 2013. 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.

The unaudited condensed consolidated financial statements attached to this MD&A and the accompanying notes for the six-month period ended June 30, 2014, along with the 2013 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.

Q2 2014 HIGHLIGHTS

- Production was 96% of long-term average ("LTA") due mainly to below-average wind regimes during the quarter
- Revenues rose 10% to $69.6 million compared with the same period last year
- Adjusted EBITDA rose 5% to $53.8 million compared with the same period last year
- The acquisition of the 30.5 MW SM-1 hydroelectric facility was completed on June 20, 2014, with partner Desjardins Group Pension Plan

TABLE OF CONTENTS

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 and Senior Vice President 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 and Senior Vice President 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 and Senior Vice President of the Corporation have certified that there were no material weaknesses relating to the DC&P and ICFR for the three-month period ended June 30, 2014. During the three-month period ended June 30, 2014, 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 and estimated project costs, to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of the potential financial impact of acquiring the SM-1 hydroelectric facility, 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; uncertainty 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 existing ones; 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; sufficiency of insurance coverage limits and exclusions; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired and to be acquired; failure to realize the anticipated benefits of acquisitions, including those of the SM-1 hydroelectric facility; reliance on shared transmission and interconnection infrastructure; the introduction of solar photovoltaic power facility operation; 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 since 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 legislation.

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 the expected LTA of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville 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
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 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.	Variability of facility performance and related penalties Changes to water and land rental expenses Unexpected maintenance expenditures
Projected Free Cash Flow and Payout Ratio 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 derivate financial instruments used to fix the interest rate on project-level debt. The Corporation estimates the Payout Ratio by dividing the most recent declared annual common share dividend by the projected Free Cash Flow.	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 The fact that the Corporation may not declare or pay a dividend

Principal Assumptions	
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 financing risk Relationships with stakeholders Regulatory and political risks Higher-than-expected inflation
Expected project financing or refinancing of Operating Facilities The Corporation provides indications of its intention to secure non-recourse project-level debt financing for its Development Projects and to refinance Operating Facilities upon the end of the term of existing project-level debt, based on the expected costs and revenues of each project, the expected remaining PPA term, an initial leverage ratio of approximately 75%-85% as well as the Corporation's extensive experience in project financing and knowledge of capital markets.	Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness
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

ADDITIONAL INFORMATION AND UPDATES

Additional and updated information on the Corporation is available through its regular press releases, quarterly financial statements and *Annual Information Form*, which can be found on the Corporation's website at www.innergex.com and on the SEDAR website at www.sedar.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.

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

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:

- 33 facilities in commercial operation (the "Operating Facilities"). Commissioned between November 1994 and January 2014, the facilities have a weighted average age of approximately 6.6 years. They sell the generated power under long-term Power Purchase Agreements ("PPA") that have a weighted average remaining life of 19.1 years (based on gross long-term average production);
- Five projects scheduled to begin commercial operation between 2015 and 2016 (the "Development Projects"). Construction is ongoing at four of the projects; and
- Numerous projects that have secured certain land rights, for which an investigative permit application has been filed or for which a proposal has either been or could be submitted under a Request for Proposal or a Standing Offer Program (collectively the "Prospective Projects"). These projects are at various stages of development.

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

INNERGEX

	Operating Facilities	Development Projects	Prospective Projects
Hydro			
Gross capacity:	547.0 MW	170.5 MW	1,000.0 MW
Net capacity[1]:	417.7 MW	134.9 MW	950.0 MW
Wind			
Gross capacity:	614.1 MW	150.0 MW	2,085.0 MW
Net capacity[1]:	236.3 MW	75.0 MW	1,910.0 MW
Solar			
Gross capacity:	33.2 MW	-	40.0 MW
Net capacity[1]:	33.2 MW	-	40.0 MW
Total			
Gross capacity:	1,194.3 MW	320.5 MW	3,125.0 MW
Net capacity[1]:	687.2 MW	209.9 MW	2,900.0 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 a high return on invested capital, and to distribute a stable dividend.

Annual Dividend Policy

The Corporation intends to distribute an annual dividend of $0.60 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.

Key Performance Indicators

The Corporation measures its performance using key performance indicators that include or could include power generated in megawatt-hours ("MWh") and gigawatt-hours ("GWh"), revenues less operating expenses, general and administrative expenses and prospective project expenses ("Adjusted EBITDA") and Adjusted EBITDA divided by revenues ("Adjusted EBITDA Margin") and dividends declared on common shares divided by Free Cash Flow ("Payout Ratio"), where Free Cash Flow is defined as cash flows from operations 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 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 PPA. Free Cash Flow is also adjusted for cash inflows or outflows 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 prior to securing such debt.

These indicators are not recognized measures under IFRS and therefore may not be comparable with those presented by other issuers. 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. The Corporation believes that these indicators are important since 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.

Diversification of Sources of Energy

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 26 hydroelectric facilities, which draw on 23 watersheds, six wind farms and one solar farm, providing significant diversification in terms of operating revenue sources. Furthermore, given the nature of hydroelectric, wind and solar power generation, seasonal variations are partially offset, as illustrated in the following table and charts:

Consolidated long-term average production[1]									
In GWh and %	Q1		Q2		Q3		Q4		Total
HYDRO	321.9	14%	815.9	35%	724.3	31%	472.8	20%	2,334.9
WIND	213.6	32%	142.8	21%	112.8	17%	207.3	31%	676.5
SOLAR[2]	7.3	19%	12.6	33%	12.7	33%	5.8	15%	38.4
Total	542.8	18%	971.3	32%	849.8	28%	685.9	22%	3,049.8

1. Annualized long-term average production ("LTA") for the facilities in operation at August 7, 2014. 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)

SECOND QUARTER UPDATE

Summary of operating and financial performance

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Power generated (MWh)	898,722	792,541	1,315,931	1,178,711
LTA (MWh)	934,874	766,961	1,433,838	1,228,490
Production as percentage of LTA	96%	103%	92%	96%
Revenues	69,649	63,167	107,248	98,855
Adjusted EBITDA	53,817	51,260	79,146	76,663
Adjusted EBITDA Margin	77.3%	81.1%	73.8%	77.6%
Net (loss) earnings	(14,189)	31,039	(52,294)	30,861
Dividend declared per Class A Preferred Share	0.3125	0.3125	0.625	0.625
Dividend declared per Class C Preferred Share[1]	0.359375	0.359375	0.718750	0.851675
Dividend declared per common share	0.150	0.145	0.300	0.290

1. The initial dividend payment in the first quarter of 2013 was higher to reflect dividends accrued since the closing date of the Series C Preferred Share offering of December 11, 2012. The regular quarterly dividend amount is $0.359375.

For the three-month period ended June 30, 2014, production was 96% of the LTA, due mainly to below-average wind regimes at all wind farms. Production increased 13%, revenues increased 10% and Adjusted EBITDA increased 5%, compared with the same period last year. For the six-month period ended June 30, 2014, production was 92% of the LTA, due mainly to below-average water flows during the first quarter, especially in British Columbia, and below-average wind regimes during the second quarter. For the first half of the year, production increased 12%, revenues increased 8% and Adjusted EBITDA increased 3%, compared with the same period last year.

For the three- and six-month periods ended June 30, 2014, the increase in production and revenues was attributable mainly to the addition of the Magpie hydroelectric facility acquired in July 2013 and the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013. The SM-1 hydroelectric facility acquired at the end of June 2014 contributed only marginally to operating results in the second quarter. Compared with the increase in production, the smaller increase in revenues was attributable to the lower average selling price for electricity, resulting mainly from the addition of the Magpie facility, for which the selling price is considerably lower than for most of the Corporation's other facilities. The modest increase in Adjusted EBITDA was attributable to higher operating expenses, due mainly to the greater number of facilities in operation and to higher prospective project expenses.

The recognition of net losses for the three- and six-month periods ended June 30, 2014, compared with net earnings for the same periods in 2013, was attributable mainly to an unrealized net loss of derivative financial instruments resulting from a decrease in benchmark interest rates during these periods, compared with an unrealized net gain on derivative financial instruments resulting from an increase in benchmark interest rates for the same periods last year.

Impact on net (loss) earnings of the unrealized net loss, the realized net loss and the unrealized net gain on derivative financial instruments	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Net (loss) earnings	(14,189)	31,039	(52,294)	30,861
Add (Subtract):				
Unrealized net loss (gain) on derivative financial instruments	29,147	(27,318)	65,177	(31,156)
Realized net loss on derivative financial instruments	—	3,259	—	3,259
Income tax (recovery) expense related to above items	(6,908)	6,255	(17,272)	7,253
Share of unrealized net loss (gain) on derivative financial instruments of joint ventures, net of related income tax recovery (expense)	485	(1,957)	1,598	(1,938)
	8,535	11,278	(2,791)	8,279

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

Excluding the unrealized net loss or gain and the realized loss on derivative financial instruments and the related income taxes, the net earnings for the three-month period ended June 30, 2014, would have been $8.5 million, compared with net earnings of $11.3 million in 2013, and the net loss for the six-month period ended June 30, 2014, would have been $2.8 million, compared with net earnings of $8.3 million in 2013, due mainly to production below the LTA, to higher operating, general and administrative and prospective project expenses and to higher finance costs attributable to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans now that the facilities are in operation and to the addition of project-level debt related to the Magpie acquisition in July 2013.

Payout Ratio

	Trailing 12-months ended June 30	
	2014	2013
Free Cash Flow[1]	48,347	56,803
Payout Ratio[1]	118%	96%

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 12-month period ended June 30, 2014, the dividends on common shares declared by the Corporation corresponded to 118% of Free Cash Flow, compared with 96% for the corresponding prior 12-month period. The negative variation is due mainly to the decrease in Free Cash Flow, resulting from greater scheduled debt principal payments and lower cash flows from operating activities, before changes in non-cash operating working capital items and realized losses on derivative financial instruments, as well as to the increase in dividends declared on common shares resulting from the higher number of shares outstanding by virtue of the Dividend Reinvestment Plan and from the issuance of 4,027,051 common shares of the Corporation to pay for the acquisition of the SM-1 hydroelectric facility.

Innergex and Desjardins Group Pension Plan acquire the 30.5 MW hydroelectric facility in Quebec

On June 20, 2014, Innergex and Desjardins Group Pension Plan ("Desjardins") announced they had completed the acquisition from Hydroméga Group of Companies ("Hydroméga") of the Sainte-Marguerite-1 ("SM-1") run-of-river hydroelectric facility located in Quebec, Canada. The transaction was closed in escrow pending customary confirmatory release conditions and was released from escrow on June 27, 2014.

Overview of the acquired asset

The 30.5 MW SM-1 hydroelectric facility is located on private land near the city of Sept-Îles, Quebec. Its long-term average annual production is expected to reach 166,500 MWh following completion of a capital improvement program already under way. The facility was commissioned in 1993 with one turbine providing an initial capacity of 8.5 MW. Two other turbines installed in 2002 provide additional capacity of 22.0 MW. All of the electricity the facility produces is covered by two 25-year fixed-price power purchase agreements with Hydro-Québec: one for 8.5 MW maturing in 2018, which provides for an annual 3% to 6% increase in the selling price; and one for 22.0 MW maturing in 2027, which provides for an annual 2% increase in the selling price. Both power purchase agreements contain a renewal option for an additional 25-year term. The water rights for this facility are owned in perpetuity. In addition, regulated water flows on the Sainte-Marguerite River from the operation of Hydro-Québec's 800 MW Sainte-Marguerite-3 hydroelectric facility upstream result in consistent production levels throughout the year.

A $5.2 million capital improvement program is under way. The program comprises the installation of a variable crest weir over the existing dam, which will increase the expected long-term average annual production of the facility by 9% or 14,000 MWh to 166,500 MWh. Work began in May 2014 and is expected to be completed by year-end.Any lost revenues expected during construction have been included in the capital improvement budget, which will be funded equally by the Corporation and Desjardins. The SM-1 facility is expected to generate annualized revenues of approximately $11.0 million and Adjusted EBITDA of approximately $9.0 million.

Partnership with Desjardins

The Corporation and Desjardins respectively own 50.01% and 49.99% of the common units of Innergex Sainte-Marguerite, S.E.C. (the "SM-1 L.P."). Concurrent with the acquisition of the SM-1 facility by the SM-1 L.P., Desjardins subscribed to a debenture issued by the SM-1 L.P. for total proceeds of approximately $40.9 million. This debenture carries an interest rate of 8.00%, has no predetermined repayment schedule and matures in 2064.

Terms of the acquisition

The purchase price of the SM-1 facility was approximately $82.1 million, plus assumption of $30.8 million in non-recourse, project-level debt carrying a fixed interest rate of 7.40% and maturing in 2025. This debt was adjusted to fair market value upon consolidation by the Corporation. In addition, the purchase price has already been reduced by approximately $1.7 million to $80.5 million to reflect the amount of net cash flows that have been generated by the facility since January 1, 2014, and are attributable to the purchasers. Other adjustments may occur, in particular after the capital improvement program has been completed. For more information on the SM-1 debt, please refer to the "Financial Position" section.

The SM-1 facility was acquired by the SM-1 L.P. for the initial purchase price of approximately $82.1 million, which was paid as follows: approximately $40.4 million in cash (from the proceeds of the debenture subscribed by Desjardins) and approximately $41.7 million by the issuance of preferred units of the SM-1 L.P., which the seller immediately transferred to Innergex in exchange for 4,027,051 newly issued common shares of the Corporation at a price of $10.36 per common share. As a result, the Corporation now holds the preferred units of the SM-1 L.P. that carry a preferred distribution rate of 10.5% until January 1, 2024 and 11.3% thereafter.

Concurrently with the closing of the acquisition, the seller used a portion of the cash proceeds to repay to the Corporation the $25.0 million deposit it received in July 2012 plus accrued interest income of $3.5 million. Innergex has used these proceeds to reduce the outstanding balance on its revolving term credit facility. The repayment of this deposit in effect terminates the letter of intent and exclusivity held by the Corporation with respect to other assets of Hydroméga.

Also concurrently with the closing of the acquisition, the second-rank guarantee provided by the SM-1 facility for another of Hydromega's projects has been lifted.

Cash flow distributions

Until January 1, 2024, all cash flows generated by the facility each year, after payment of the principal and interest expense on the existing project-level debt, will go first toward paying the preferred distribution to the Corporation. Any remaining cash flows will then go toward paying the interest expense to Desjardins. Subsequently, any remaining cash flow will be distributed between Innergex and Desjardins on a 50.01%-49.99% basis. Any unpaid preferred distribution will be accrued and any unpaid interest expense will be accrued and compounded.

Starting in 2024, all cash flows generated by the facility each year, after payment of the principal and interest expense on the existing project-level debt, if any, will be shared between the partners to concurrently service the distribution and the interest on the debenture. Any remaining cash flows will then be distributed between the partners on a 50.01%-49.99% basis.

Taking into account the preferred distribution and the operating and management fees it will receive, all of which will be adjusted annually for inflation, the Corporation expects this acquisition to contribute approximately $5.0 million annually to its Free Cash Flow and to reduce its Payout Ratio by approximately three percentage points.

Benefits of the acquisition

- Increases annualized Free Cash Flow by approximately $5.0 million
- Reduces the Corporation's Payout Ratio by approximately three percentage points on an annual basis
- Adds a high-quality, long-term hydro asset
- Provides a new watershed with a regulated water flow
- Carries perpetual land and water rights
- Introduces a new capital structure that optimizes the return on the acquired assets
- Deposit refund reduces the outstanding balance of the revolving term credit facility

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

DEVELOPMENT PROJECTS

The Corporation currently has five projects that are expected to reach commercial operation between 2015 and 2016.

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] ($M)	As at Jun. 30 ($M)	Revenues[2] ($M)	Adjusted EBITDA[2] ($M)
HYDRO (British Columbia)									
Tretheway Creek	100.0	23.2	2015	81.9	40	111.5	42.1	9.0	7.5
Upper Lillooet River	66.7	81.4	2016	334.0	40	315.0 [4]	76.8 [4]	33.0 [4]	27.5 [4]
Boulder Creek	66.7	25.3	2016	92.5	40	119.2 [4]	18.3 [4]	9.0 [4]	7.5 [4]
Big Silver Creek	100.0	40.6	2016	139.8	40	216.0	40.5	18.0	15.0
		170.5		648.2		761.7	177.7	69.0	57.5

1. Commercial operation date.
2. This information is intended to inform readers of the projects' potential impact on the Corporation's results.
3. Upon commissioning, LTA figures may be updated to reflect design optimization or constraints or selection of different turbines. Actual results may vary. Please refer to the "Forward-Looking Information" section for more information.
4. Corresponding to 100% of this facility.

Tretheway Creek

The construction of this hydroelectric facility began in October 2013. As at the date of this MD&A, installation of the penstock was ongoing; construction of the overflow weir and diversion channel was completed; excavation for the powerhouse and switchyard was also completed; pouring of the concrete for the powerhouse foundation was in progress; and design and procurement of electrical equipment was ongoing. In January 2014, a hedging program was for all intents and purposes completed to fix the interest rate for this project's financing through the use of derivative financial instruments until closing of the project-level financing; this effectively eliminates the project's exposure to interest rate fluctuations.

Upper Lillooet River and Boulder Creek (the "Upper Lillooet Hydro Project")

The construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities began in October 2013. As at the date of this MD&A, the construction camp is operational; most of the clearing work has been completed for both sites; construction of a new 4 km road and bridge has been completed and construction of a 3.6 km access road to the Boulder Creek intake is almost complete. Excavation is progressing for the Upper Lillooet River intake diversion channel, tunnel and powerhouse and for the Boulder Creek tunnel. Clearing for the joint transmission line and pole installation are ongoing, in preparation for providing temporary power to the construction site by the Fall. In January 2014, a hedging program was for all intents and purposes completed to fix the interest rate for these projects' financing through the use of derivative financial instruments until closing of the project-level financing; this effectively eliminates the projects' exposure to interest rate fluctuations.

Big Silver Creek

Construction of this hydroelectric facility began in June 2014, upon receipt of the Leave to Commence Construction. As of the date of this MD&A, clearing for the intake, penstock and powerhouse was completed; construction of a permanent intake access bridge was also completed; excavation for the powerhouse was ongoing; and excavation for the intake and penstock was under way. In January 2014, a hedging program was for all intents and purposes completed to fix the interest rate for this project's financing through the use of derivative financial instruments until closing of the project-level financing; this effectively eliminates the project's exposure to interest rate fluctuations.

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

PROJECTS UNDER PERMIT PHASE	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] ($M)	As at Jun. 30 ($M)	Revenues[2] ($M)	Adjusted EBITDA[2] ($M)
WIND (Quebec)									
Mesgi'g Ugju's'n	50.0	150.0	2016	515.0	20	365.0 [4]	3.9 [4]	55.0 [4]	45.0 [4]
		150.0		515.0		365.0	3.9	55.0	45.0

1. Commercial operation date.
2. This information is intended to inform readers of the projects' potential impact on the Corporation's results.
3. Upon commissioning, LTA figures may be updated to reflect design optimization or constraints or selection of different turbines. Estimates for the Mesgi'g Ugju's'n project in particular are preliminary until the turbine supplier and EPC contractor have been selected. Actual results may vary. Please refer to the "Forward-Looking Information" section for more information.
4. Corresponding to 100% of this facility.

Mesgi'g Ugju's'n

As at the date of this MD&A, negotiations with potential turbine suppliers were ongoing and a selection should be made by the Fall. Since there has been no request for a public hearing pursuant to the province's environmental review process, there will be no hearing and the project is expected to receive the government decree by the Fall. Pre-construction activities are expected to start in late 2014, construction is expected to start in 2015 and commercial operation is expected to begin at the end of 2016. In April 2014, a hedging program was for all intents and purposes completed to fix the interest rate for this project's financing through the use of derivative financial instruments until closing of the project-level financing; this effectively eliminates the project's exposure to interest rate fluctuations.

PROSPECTIVE PROJECTS

With a combined potential net installed capacity of 2,900 MW (gross 3,125 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 proposals for 450 MW of new wind energy procurement in Quebec, an upcoming request for proposals for new wind and solar energy in Ontario expected in 2015, or Standing Offer Programs, while others will be available for future requests for proposals yet to be announced. There is no certainty that any Prospective Project will be realized.

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

OPERATING RESULTS

Production of electricity for the second quarter was 96% of the long-term average due mainly to below-average wind regimes.

For the second quarter, production increased 13%, revenues increased 10% and Adjusted EBITDA increased 5% respectively, compared with the same period last year. The increase in production and revenues is attributable mainly to the addition of the Magpie hydroelectric facility acquired in July 2013 and the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013. The SM-1 hydroelectric facility acquired at the end of June 2014 contributed only marginally to the second quarter operating results. The smaller increase in revenues is attributable to the lower average selling price for electricity, resulting mainly from the addition of the Magpie facility, for which the selling price is considerably lower than for most other facilities of the Corporation. The more modest increase in Adjusted EBITDA is attributable to higher operating expenses and prospective project expenses.

The Corporation's operating results for the three- and six-month periods ended June 30, 2014, are compared with the operating results for the same periods in 2013.

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 ("LTA") for each hydroelectric facility, wind farm and solar farm. These long-term averages are determined to allow long-term forecasting of the expected power generation for each of the Corporation's facilities.

Three months ended June 30	2014				2013			
	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	183,152	177,639	103%	71.74	120,626	117,910	102%	83.16
Ontario	19,120	20,805	92%	65.80	23,386	20,805	112%	65.73
British Columbia	545,089	564,115	97%	70.79	475,580	455,841	104%	71.10
United States	20,395	16,956	120%	66.95	19,402	16,956	114%	63.45
Subtotal	767,756	779,515	98%	70.79	638,994	611,512	104%	72.94
WIND								
Quebec	116,747	142,805	82%	79.90	140,551	142,805	98%	78.96
SOLAR								
Ontario	14,219	12,554	113%	420.00	12,997	12,644	103%	420.00
Total	898,722	934,874	96%	77.50	792,542	766,961	103%	79.70

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 June 30, 2014, the Corporation's facilities produced 899 GWh of electricity or 96% of the LTA of 935 GWh. Overall, the hydroelectric facilities produced 98% of their LTA, as water flows were above-average in Quebec and the United States, below-average in Ontario and only slightly below average in British Columbia. Overall, the wind farms produced 82% of their LTA, due to below-average wind regimes. The Stardale solar farm produced 113% of its LTA, due to above-average solar regimes.

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

Six months ended June 30	2014				2013			
	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	257,315	257,952	100%	79.23	191,312	181,227	106%	92.82
Ontario	44,185	45,099	98%	68.39	48,927	45,099	108%	68.03
British Columbia	626,125	729,604	86%	73.31	551,782	600,838	92%	73.63
United States	26,700	24,883	107%	65.88	23,531	24,883	95%	62.62
Subtotal	954,325	1,057,538	90%	74.47	815,552	852,047	96%	77.48
WIND								
Quebec	339,973	356,410	95%	79.70	343,227	356,410	96%	79.53
SOLAR								
Ontario	21,633	19,890	109%	420.00	19,932	20,033	99%	420.00
Total	1,315,931	1,433,838	92%	81.50	1,178,711	1,228,490	96%	83.87

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 six-month period ended June 30, 2014, the Corporation's facilities produced 1,316 GWh of electricity or 92% of the LTA of 1,434 GWh. Overall, the hydroelectric facilities produced 90% of their LTA, due mainly to below-average water flows during the first quarter, especially in British Columbia. Overall, the wind farms produced 95% of their LTA, due mainly to below-average wind regimes during the second quarter, which more than offset the first quarter's above-average wind regimes. The Stardale solar farm produced 109% of its LTA, due mainly to above-average solar regimes during the second quarter.

The production increases of 13% and 12% for the three- and six-month periods ended June 30, 2014, respectively, compared with the same periods last year, are attributable mainly to the addition of the Magpie hydroelectric facility acquired in July 2013 and the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013.The SM-1 hydroelectric facility acquired in June 2014 contributed only marginally to operating results during the second quarter.

The overall performance of the Corporation's facilities for the six-month period ended June 30, 2014, 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 June 30				Six months ended June 30			
	2014		2013		2014		2013	
Revenues	69,649	100.0%	63,167	100.0%	107,248	100.0%	98,855	100.0%
Operating expenses	11,025	15.8%	8,259	13.1%	18,670	17.4%	14,717	14.9%
General and administrative expenses	3,330	4.8%	2,924	4.6%	6,884	6.4%	5,926	6.0%
Prospective project expenses	1,477	2.1%	724	1.1%	2,548	2.4%	1,549	1.6%
Adjusted EBITDA	53,817	77.3%	51,260	81.1%	79,146	73.8%	76,663	77.6%
Finance costs	24,469		18,826		44,133		31,778	
Other net (revenues) expenses	(739)		2,958		(912)		585	
Depreciation and amortization	18,931		17,452		37,778		34,913	
Share of (earnings) loss of joint ventures[1]	(204)		(3,832)		792		(3,706)	
Unrealized net loss (gain) on derivative financial instruments	29,147		(27,318)		65,177		(31,156)	
(Recovery of) income tax expense	(3,598)		12,135		(15,528)		13,388	
Net (loss) earnings	(14,189)		31,039		(52,294)		30,861	
Net (loss) earnings attributable to:								
Owners of the parent	(7,835)		28,302		(35,254)		31,099	
Non-controlling interests	(6,354)		2,737		(17,040)		(238)	
	(14,189)		31,039		(52,294)		30,861	
Basic net (loss) earnings per share	(0.10)		0.28		(0.40)		0.29	

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 period ended June 30, 2014, the Corporation recorded revenues of $69.6 million, compared with $63.2 million in 2013, corresponding to a 10% increase. For the six-month period ended June 30, 2014, the Corporation recorded revenues of $107.2 million, compared with $98.9 million in 2013, corresponding to an 8% increase. Both increases are attributable mainly to the addition of the Magpie hydroelectric facility acquired in July 2013 and the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013. The SM-1 hydroelectric facility acquired at the end of June 2014 contributed only marginally to the second quarter's operating results. Furthermore, the smaller increase in revenues is attributable to the lower average selling price for electricity, resulting mainly from the addition of the Magpie facility, for which the selling price is considerably lower than for most of the Corporation's other facilities.

Expenses

Operating expenses: consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes, and royalties. For the the three- and six-month periods ended June 30, 2014, the Corporation recorded operating expenses of $11.0 million and $18.7 million respectively ($8.3 million and $14.7 million respectively in 2013). This increase of 33% for the quarter and 27% for the six-month period is due mainly to the Corporation operating a greater number of facilities in 2014 than in 2013 following the addition of the Magpie, Kwoiek Creek and Northwest Stave River hydroelectric facilities. In addition, the aggregate payment in respect of water rights for the Douglas Creek, Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River facilities increased $1.4 million compared with the same period last year. This change resulted from a unilateral decision by British Columbia's Ministry of Forests, Lands and Natural Resource Operations in 2013 to apply higher rental rates based on the combined production of these facilities rather than applying lower rates for each facility based on its individual production, as had previously been its practice. The Corporation has filed an appeal of this decision with the Environmental Appeal Board.

General and administrative expenses: consist primarily of salaries, professional fees and office expenses. For the three- and six-month periods ended June 30, 2014, general and administrative expenses totalled $3.3 million and $6.9 million respectively ($2.9 million and $5.9 million respectively in 2013). This increase of 14% for the quarter and 16% for the six-month period reflects the Corporation's greater number of facilities in operation, greater number of employees and normal salary increases.

Prospective project expenses: include the costs incurred for the development of Prospective Projects. They result from the number of Prospective Projects that the Corporation chooses to advance and the resources required to do so. For the three- and six-month periods ended June 30, 2014, prospective project expenses totalled $1.5 million and $2.5 million respectively ($0.7 million and $1.5 million respectively in 2013). This increase of 104% for the quarter and 64% for the six-month period is related to the current request for proposals in Quebec and the upcoming request for proposals in Ontario.

Adjusted EBITDA

When evaluating its financial results, a key performance indicator for the Corporation is to measure Adjusted EBITDA, which is defined as revenues less operating expenses, general and administrative expenses and prospective project expenses.

For the three- and six-month periods ended June 30, 2014, the Corporation recorded Adjusted EBITDA of $53.8 million and $79.1 million respectively, compared with $51.3 million and $76.7 million respectively for the same periods last year. When compared with the increases in production and revenues described above, the smaller increase in Adjusted EBITDA of 5% for the quarter and 3% for the six-month period is attributable to the higher operating, general and administrative and prospective project expenses, which are not directly correlated to production levels. Consequently, the Adjusted EBITDA Margin decreased from 81.1% to 77.3% for the quarter and from 77.6% to 73.8% for the six-month period.

Finance Costs

Finance costs include interest on long-term debt and convertible debentures, inflation compensation interest, amortization of financing fees, amortization of the revaluation of long-term debt and convertible debentures, accretion expenses on other liabilities and other finance costs. For the three- and six-month periods ended June 30, 2014, finance costs totalled $24.5 million and $44.1 million respectively ($18.8 million and $31.8 million respectively in 2013). These increases are due mainly to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans now that the facilities are in operation, to the addition of project-level debt related to the Magpie acquisition in July 2013, to higher interest expense on the higher project-level debt for the Carleton wind farm refinanced in June 2013 and to greater inflation compensation interest on the real return bonds owing to higher inflation during these periods compared with the same periods last year.

As at June 30, 2014, 95% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (96% as at June 30, 2013). The effective all-in interest rate on the Corporation's debt and convertible debentures was 5.39% as at June 30, 2014 (5.61% as at June 30, 2013). The decrease stems mainly from a lower interest rate on the revolving term credit facility, the addition of the Northwest Stave River loan, which bears a low fixed-interest rate of 5.30%, the addition of the Magpie project debt, which bears an all-in interest rate of 4.48%, and the addition of the SM-1 project debt, which bears an all-in interest rate of 3.30% following its adjustment to fair market value upon consolidation, partly offset by the refinancing in June 2013 of the Carleton loan at a higher all-in interest rate of 5.41% (4.84% previously), which has been hedged by an interest-rate swap contract since November 2008, and by the addition of the debenture on the SM-1 facility, which bears an interest rate of 8.00%.

Other Net (Revenues) Expenses

Other net revenues or expenses include transaction costs, realized losses on derivative financial instruments, realized losses on foreign exchange, settlement of claims received in connection with an acquisition and other net revenues. For the three- and six-month periods ended June 30, 2014, the Corporation recorded other net revenues of $0.7 million and $0.9 million respectively (other net expenses of $3.0 million and $0.6 million respectively in 2013). The variation in the second quarter stems mainly from the realized loss on derivative financial instruments of $3.3 million recorded in the second quarter of 2013 and related to the settlement of the Northwest Stave bond forward contracts concurrently with the closing of the long-term financing for this project. The variation for the six-month period stems mainly from the same realized loss on derivative financial instruments, partly offset by a $2.0 million claims settlement received in the first quarter of 2013.

Depreciation and Amortization

For the three- and six-month periods ended June 30, 2014, depreciation and amortization expenses totalled $18.9 million and $37.8 million respectively ($17.5 million and $34.9 million respectively in 2013). These increases are attributable mainly to the larger asset base resulting from the addition of the Magpie hydroelectric facility and the start of operations of the Kwoiek Creek and Northwest Stave River hydroelectric facilities. Taken alone, amortization expenses decreased slightly for these periods as a result of a change in accounting estimates to amortize the intangible assets of the Quebec hydroelectric facilities, which reflects the renewal rights of their PPAs for periods of 20 to 25 years.

Share of Earnings (Loss) of Joint Ventures

For the three- and six-month periods ended June 30, 2014, the Corporation recorded a share of earnings of joint ventures of $0.2 million and a share of loss of joint ventures of $0.8 million respectively (share of earnings of joint ventures of $3.8 million and $3.7 million respectively in 2013). For the Umbata Falls hydroelectric facility, above-average production and positive Adjusted EBITDA were relatively unchanged from the same periods last year but were offset by an unrealized net loss on derivative financial instruments recorded as a result of a decrease in benchmark interest rates since the end of 2013, compared with an unrealized net gain following an increase in benchmark interest rates for the same periods last year. For the Viger-Denonville wind farm, the positive contribution of Adjusted EBITDA following the start of commercial operations in November 2013 was also offset by an unrealized net loss on derivative financial instruments. Please refer to the "Investments in Joint Ventures" section for more information.

Derivative Financial Instruments

The Corporation uses derivative financial instruments to manage its exposure to the risk of rising interest rates on its debt financing (“Derivatives”), thereby protecting the economic value of its projects. Innergex also has derivative financial instruments embedded in some of its PPAs (the minimum 3% inflation clause applied to the selling price). The Corporation does not use hedge accounting for its derivative financial instruments nor does it own or issue financial instruments for speculative purposes. Since several interest rate swaps are entered into for a term equal in length to the underlying debt amortization schedule, which can reach 30 years, a Derivative's fair market value can be very sensitive to quarter-to-quarter variations in long-term interest rates.

For the three- and six-month periods ended June 30, 2014, the Corporation recognized an unrealized net loss on derivative financial instruments of $29.1 million and $65.2 million respectively, due mainly to the decrease in benchmark interest rates since the end of 2013. For the corresponding periods of 2013, Innergex recognized an unrealized net gain on derivative financial instruments of $27.3 million and $31.2 million respectively, due mainly to the increase in benchmark interest rates since December 31, 2012.

In January 2014, the Corporation completed a hedging program to fix the interest rate on future project-level debt for the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek Development Projects. In April 2014, the Corporation and its partner completed a hedging program to fix the interest rate on the future project-level debt for the Mesgi'g Ugju's'n Development Project. As at the date of this MD&A, the Corporation had entered into derivative financial instruments totalling $595.0 million. Upon the closing of each fixed-rate or interest-swapped long-term financing, the Corporation will settle the corresponding derivative financial instruments, which will result in a realized gain or loss on derivative financial instruments. These gains or losses will serve to offset a higher or lower interest rate on the project-level debt. As at June 30, 2014, the Derivatives to be settled upon closing of financing had a negative market value of $44.3 million.

(Recovery of) Income Tax Expense

For the three- and six-month periods ended June 30, 2014, the Corporation recorded a current income tax expense of $0.8 million and $1.6 million respectively ($0.9 million and $1.7 million in 2013) and deferred income tax recovery of $4.4 million and $17.1 million respectively (expense of $11.3 million and $11.7 million in 2013). The difference in the deferred income tax for these periods is due primarily to an unrealized net loss on derivative financial instruments, compared with an unrealized net gain on derivative financial instruments for the same periods last year.

Non-controlling Interests

Non-controlling interests are related to the six hydroelectric facilities of the Harrison Hydro Limited Partnership, the Creek Power Inc. subsidiaries, the Kwoiek Creek Resources Limited Partnership, the Mesgi'g Ugju's'n (MU) Wind Farm, L.P., the Magpie Limited Partnership, the Innergex Sainte-Marguerite S.E.C. entity and their respective general partners. For the three- and six-month periods ended June 30, 2014, the Corporation allocated losses of $6.4 million and $17.0 million respectively to non-controlling interests (earnings of $2.7 million and losses of $0.2 million respectively in 2013). The variations during these periods are due mainly to the recognition of unrealized net losses on derivative financial instruments at the Creek Power and MU subsidiaries, to net losses at the Kwoiek Creek subsidiary and to lower Adjusted EBITDA and greater inflation compensation interest at the Harrison Hydro L.P. Please refer to the "Non-Wholly Owned Subsidiaries" section for more information.

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

Net (Loss) Earnings

For the three-month period ended June 30, 2014, the Corporation recorded a net loss of $14.2 million (basic and diluted net loss of $0.10 per share), compared with net earnings of $31.0 million (basic and diluted net earnings of $0.28 per share) in 2013.

Main items contributing to the net loss for the three months ended June 30, 2014, compared with the net earnings for the corresponding period in 2013		
Main items – Positive impact	Variation	Explanation
Revenues	6,482	Due mainly to the increase in production from the greater number of facilities in operation.
Deferred recovery of income tax	15,724	Due mainly to an unrealized net loss on derivative financial instruments.
Main items – Negative impact	Variation	Explanation
Unrealized net loss on derivative financial instruments	56,465	Due mainly to a decrease in benchmark interest rates during the quarter, compared with an increase in benchmark interest rates during the same period last year.
Finance costs	5,643	Due mainly to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans following their commissioning, the addition of project-level debt related to Magpie and higher inflation compensation interest on the real return bond.
Share of (earnings) loss of joint ventures	3,628	Due mainly to unrealized net losses on Derivatives as a result of a decrease in benchmark interest rates during the quarter, compared with an unrealized gain on Derivatives as a result of an increase in benchmark interest rates during the same period last year.

For the six-month period ended June 30, 2014, the Corporation recorded a net loss of $52.3 million (basic and diluted net loss of $0.40 per share), compared with a net earnings of $30.9 million (basic and diluted net earnings of $0.29 per share) in 2013.

Main items contributing to the net loss for the six months ended June 30, 2014, compared with the net earnings for the corresponding period in 2013		
Main items – Positive impact	Variation	Explanation
Revenues	8,393	Due mainly to the increase in production from the greater number of facilities in operation.
Deferred recovery of income tax	28,854	Due mainly to an unrealized net loss on derivative financial instruments.
Main items – Negative impact	Variation	Explanation
Unrealized net loss on derivative financial instruments	96,333	Due mainly to a decrease in benchmark interest rates during the six-month period, compared with an increase in benchmark interest rates during the same period last year.
Finance costs	12,355	Due mainly to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans following their commissioning, the addition of project-level debt related to Magpie and higher inflation compensation interest on the real return bond.
Share of (earnings) loss of joint ventures	4,498	Due mainly to unrealized net losses on Derivatives as a result of a decrease in benchmark interest rates during the six-month period, compared with an unrealized gain on Derivatives as a result of an increase in benchmark interest rates during the same period last year.

Number of Shares Outstanding

Weighted average number of common shares outstanding (000s)	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Weighted average number of common shares	96,513	94,370	96,172	94,142
Effect of dilutive elements on common shares[1]	201	63	179	77
Diluted weighted average number of common shares	96,714	94,433	96,351	94,219

1. For the three-month period ended June 30, 2014, 1,243,000 of 3,073,684 stock options (2,073,420 of 2,736,684 for the three-month period ended June 30, 2013) and 7,558,684 shares that can be issued on conversion of convertible debentures (7,558,684 for the three-month period ended June 30, 2013) were excluded from the calculation of diluted weighted average number of shares outstanding as the exercise price was above the common shares' average market price.

   For the six-month period ended June 30, 2014, 1,243,000 of 3,073,684 stock options (1,263,000 of 2,736,684 for the six-month period ended June 30, 2013) and 7,558,684 shares that can be issued on conversion of convertible debentures (7,558,684 for the six-month period ended June 30, 2013) were excluded from the calculation of the diluted weighted average number of shares outstanding as the exercise price was above the common shares' average market price.

As at June 30, 2014, the Corporation had a total of 100,085,875 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 3,073,684 stock options outstanding. As at June 30, 2013, it had 94,449,724 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 2,736,684 stock options outstanding. The increase in the number of common shares since June 30, 2013, is attributable to the issuance of 4,027,051 shares following the SM-1 acquisition and to the Dividend Reinvestment Plan ("DRIP").

As at the date of this MD&A, the Corporation had a total of 100,372,867 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 3,073,684 stock options outstanding. The increase in the number of common shares since June 30, 2014, is attributable to the DRIP.

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

LIQUIDITY AND CAPITAL RESOURCES

For the six-month period ended June 30, 2014, the Corporation generated cash flows from operating activities of $19.7 million, compared with generating $48.0 million for the same period last year. During this period, the Corporation generated funds from financing activities of $31.6 million and used funds for investing activities of $58.0 million, mainly to pay for the construction of its five Development Projects and the acquisition of the SM-1 hydroelectric facility. As at June 30, 2014, the Corporation had cash and cash equivalents amounting to $27.5 million, compared with $34.3 million as at December 31, 2013.

Cash Flows from Operating Activities

For the six-month period ended June 30, 2014, cash flows generated by operating activities totalled $19.7 million ($48.0 million generated in 2013). This variation is attributable mainly to higher finance costs and a negative net variation of $23.0 million in non-cash operating working capital items.

Cash Flows from Financing Activities

For the six-month period ended June 30, 2014, cash flows generated by financing activities totalled $31.6 million ($16.9 million in 2013). This variation is attributable mainly to a net increase in long-term debt of $59.4 million, reflecting drawings on the revolving term credit facility to pay for construction activity of the five Development Projects, partly offset by the reduction of drawings following the reimbursement of the loan to the seller of SM-1.

Use of Financing Proceeds	Six months ended June 30	
	2014	2013
Proceeds from issuance of long-term debt	131,166	121,414
Payment of issuance cost of common and preferred shares	(11)	(353)
Generation of financing proceeds	131,155	121,061
Repayment of long-term debt	(71,639)	(78,767)
Payment of deferred financing costs	(157)	(2,746)
Payment of other liabilities	(113)	—
Business acquisitions	(37,901)	—
Decrease in restricted cash and short-term investments	22,751	2,825
Loans to related parties	—	(13,452)
Net funds withdrawn from (invested into) the reserve accounts	1,715	(73)
Additions to property, plant and equipment	(58,273)	(51,811)
Additions to project development costs	(15,494)	(10,229)
Withdrawals from (investments in) joint ventures	2,259	(5,484)
Reductions (additions) to other long-term assets	26,868	(186)
Net use of financing proceeds	(129,984)	(159,951)
Increase in (reduction of) working capital	1,171	(38,890)

During the six-month period ended June 30, 2014, the Corporation borrowed $131.2 million to pay for construction of the Upper Lillooet River, Boulder Creek, Tretheway Creek, and Big Silver Creek projects and for the pre-construction development of the Mesgi'g Ugju's'n project, to pay for the acquisition of the SM-1 hydroelectric facility and to repay long-term debts; it also used $22.8 million in restricted cash to pay for construction costs related to the Kwoiek Creek and Northwest Stave River facilities. During the corresponding period of 2013, the Corporation borrowed $121.4 million and used $38.9 million of its working capital to pay for the construction of the Gros-Morne, Kwoiek Creek and Northwest Stave River projects, to pay for the pre-construction activities related to its Development Projects, to repay long-term debts and to reduce drawings under the revolving term credit facility.

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

Cash Flows from Investing Activities

For the six-month period ended June 30, 2014, cash flows used by investing activities amounted to $58.0 million ($78.4 million in 2013). During this period, additions to property, plant and equipment accounted for a $58.3 million outflow ($51.8 million outflow in 2013), additions to project development costs, which accounted for a $15.5 million outflow ($10.2 million outflow in 2013), and the acquisition of the SM-1 hydroelectric facility, which accounted for a $37.9 million outflow (nil in 2013). These items were partly offset by a decrease in other long-term assets, which accounted for a $26.9 million inflow ($0.2 million outflow in 2013), due mainly to the reimbursement of the loan to the seller of SM-1, by a decrease in restricted cash and short-term investments, which accounted for a $22.8 million inflow ($2.8 million inflow in 2013), and by a reduction in investments in joint ventures, which accounted for a $2.3 million inflow ($5.5 million outflow in 2013).

Cash and Cash Equivalents

For the six-month period ended June 30, 2014, cash and cash equivalents decreased by $6.8 million (decreased by $13.4 million in 2013) as a net result of its operating, financing and investing activities. As at June 30, 2014, the Corporation had cash and cash equivalents amounting to $27.5 million ($34.3 million as at December 31, 2013).

DIVIDENDS

The following dividends were declared by the Corporation:

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Dividends declared on common shares[1]	15,013	13,695	29,392	27,320
Dividends declared on common shares ($/share)[1]	0.1500	0.1450	0.3000	0.2900
Dividends declared on Series A Preferred Shares	1,063	1,063	2,125	2,125
Dividends declared on Series A Preferred Shares ($/share)	0.3125	0.3125	0.625	0.625
Dividends declared on Series C Preferred Shares[2]	719	719	1,438	1,703
Dividends declared on Series C Preferred Shares ($/share)[2]	0.359375	0.359375	0.718750	0.851675

1. On February 25, 2014, the Board of Directors increased the annual dividend that the Corporation intends to distribute from $0.58 to $0.60 per common share, payable quarterly. On June 20, 2014, the Corporation issued 4,027,051 new common shares to pay for the acquisition of the SM-1 hydroelectric facility.
2. The initial dividend payment in the first quarter of 2013 was higher to reflect dividends accrued since the closing date of the Series C Preferred Share offering of December 11, 2012. The regular quarterly dividend amount is $0.359375.

The following dividends will be paid by the Corporation on October 15, 2014:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
8/7/2014	9/30/2014	10/15/2014	0.1500	0.3125	0.359375

FINANCIAL POSITION

As at June 30, 2014, the Corporation had $2,521 million in total assets, $1,899 million in total liabilities, including $1,444 million in long-term debt and $622.2 million in shareholders' equity.

Also at June 30, 2014, the Corporation had a working capital ratio of 0.75:1.00 (1.18:1.00 as at December 31, 2013). In addition to cash and cash equivalents amounting to $27.5 million, the Corporation had restricted cash and short-term investments of $27.0 million and reserve accounts of $46.1 million at the end of the quarter.

The explanations below highlight the most significant changes in balance sheet items during the six-month period ended June 30, 2014.

Assets

Highlights of significant changes in total assets during the six-month period ended June 30, 2014

- A net decrease in cash and cash equivalents and restricted cash and short-term investments from $84.0 million as at December 31, 2013, to $54.5 million as at June 30, 2014, due mainly to amounts being drawn to pay for construction of the Kwoiek Creek and Northwest Stave River projects;
- An increase in accounts receivable from $19.8 million to $42.1 million, as explained in the "Working Capital Items" section below;
- A $185.3 million increase in property, plant and equipment, due mainly to construction of the Tretheway Creek, Boulder Creek, Upper Lillooet River and Big Silver Creek projects and to the addition of the SM-1 hydroelectric facility acquired in June 2014;
- A $32.0 million increase in intangible assets, due mainly to the transfer of the Big Silver Creek project out of project development costs and into property, plant and equipment and intangible assets now that construction of the project has begun and to the addition of the SM-1 hydroelectric facility acquired in June 2014;
- A $26.4 million decrease in project development costs, due mainly to the transfer of the Big Silver Creek project out of project development costs and into property, plant and equipment and intangible assets now that construction of the project has begun; and
- A $26.9 million decrease in other long-term assets, due mainly to the reimbursement of the $25.0 million loan to the seller of SM-1, plus accrued interest, concurrent with the closing of the acquisition of the SM-1 hydroelectric facility in June 2014.

Working Capital Items

As at June 30, 2014, working capital was negative at $34.6 million with a working capital ratio of 0.75:1.00. As at December 31, 2013, working capital was positive at $19.1 million with a working capital ratio of 1.18:1.00. The decrease in the working capital ratio over this period is due to a decrease of $6.8 million in cash and cash equivalents, of $22.8 million in restricted cash and short-term investments and of $6.8 million in loans to related parties, to an increase of $44.0 million in the current liability portion of derivative financial instruments and to an increase of $6.1 million in the current portion of long-term debt, which are explained separately below. These items were partly offset by the $22.3 million increase in accounts receivable and the $16.1 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 June 30, 2014, the Corporation had drawn US$13.9 million and $201.4 million as cash advances, while $32.2 million had been used for issuing letters of credit.

Restricted cash and short-term investments: are related to the Harrison Hydro L.P., the Kwoiek Creek loan and the Northwest Stave River loan. As at June 30, 2014, restricted cash and short-term investments amounted to $27.0 million, of which $6.7 million was related to the Harrison Hydro L.P., $16.0 million to the Kwoiek Creek loan and $4.3 million to the Northwest Stave River loan ($49.7 million as at December 31, 2013, of which $6.7 million was related to the Harrison Hydro L.P., $31.5 million to the Kwoiek Creek loan and $11.6 million to the Northwest Stave River loan). The decrease stems mainly from amounts being drawn to pay for construction of the Kwoiek Creek and Northwest Stave River projects.

Accounts receivable: increased from $19.8 million as at December 31, 2013, to $42.1 million as at June 30, 2014, due mainly to revenues generated.

Loans to related parties: decreased from $6.8 million as at December 31, 2013, to nil as at June 30, 2014, as the Harrison Hydro L.P. completed a distribution that resulted in a $6.8 million decrease in loans to related parties and a corresponding decrease in non-controlling interests with no impact on net earnings or cash flows.

Accounts payable and other payables: decreased from $48.3 million as at December 31, 2013, to $32.1 million as at June 30, 2014, due mainly to payments made in relation to the construction of the Kwoiek Creek and Northwest Stave River facilities.

Derivative financial instruments included in current liabilities: increased from $12.9 million as at December 31, 2013, to $56.9 million as at June 30, 2014, due mainly to the increase in bond forward contracts entered into to hedge the interest rate on future project-level financing for the Development Projects, and to the decrease in benchmark interest rates since December 31, 2013. These short-term derivatives will be refinanced with long-term project-level debt in the coming months.

Portion of long-term debt included in current liabilities: increased from $26.6 million as at December 31, 2013, to $32.7 million as at June 30, 2014, due mainly to the addition of the SM-1 project-level debt and to a cash call from the Harrison Hydro L.P. to its limited partners.

Property, Plant and Equipment

Property, plant and equipment are comprised mainly of hydroelectric facilities, wind farms and a solar farm that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses. The Corporation had $1,769 million in property, plant and equipment as at June 30, 2014, compared with $1,583 million as at December 31, 2013. The increase stems mainly from the ongoing construction of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects, from the addition of the SM-1 hydroelectric facility acquired in June 2014, and from the transfer of the Big Silver Creek project out of project development costs now that construction of the project has begun. This increase was 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 $498.1 million in intangible assets as at June 30, 2014, compared with $466.1 million as at December 31, 2013. The increase stems mainly from the transfer of $23.2 million in intangible assets related to the Big Silver Creek project out of project development costs now that construction of the project has begun and from the addition of $19.2 million in intangible assets related to the SM-1 hydroelectric facility acquired in June 2014. The increase was partly offset by amortization.

Project Development Costs

Project development costs are the costs to acquire and develop Development Projects and to acquire Prospective Projects. Depending on their nature, these costs are transferred either to property, plant and equipment or to intangible assets once the project reaches the construction phase. The Corporation had $55.3 million in project development costs as at June 30, 2014, compared with $81.6 million as at December 31, 2013. The decrease stems mainly from the transfer of the Big Silver Creek project out of project development costs and into property, plant and equipment and intangible assets now that construction of the project has begun.

Other Long-Term Assets

Other long-term assets consist of security deposits, investments and loans to third parties. The Corporation had $6.4 million in other long-term assets as at June 30, 2014, compared with $33.2 million as at December 31, 2013. The decrease stems mainly from the reimbursement of the $25.0 million loan to the seller of SM-1, plus accrued interest, concurrent with the closing of the acquisition of the SM-1 hydroelectric facility in June 2014.

Liabilities and Shareholders' Equity

Derivative Financial Instruments and Risk Management

The Corporation uses derivative financial instruments to manage its exposure to the risk of increasing interest rates on its debt financing. The Corporation does not own or issue any Derivatives for speculation purposes. The Corporation does not use hedge accounting to account for its Derivatives. Interest rate swap contracts allow the Corporation to eliminate the risk of interest rate increases in actual floating-rate debts, which debts totalled $479.3 million as at June 30, 2014. Consequently, as at June 30, 2014, interest rate swaps related to outstanding debts combined with the $895.8 million in existing fixed-rate debts and $79.9 million in convertible debentures mean that 95% of outstanding debts, including those of joint ventures, are protected from interest rate increases.

In addition, bond forward contracts allow the Corporation to eliminate the risk of interest rate increases in planned long-term debt that it will need to secure for its Development Projects. As at the date of this MD&A, the Corporation had entered into bond forward contracts totalling $595.0 million ($340.0 million as at December 31, 2013) for the Upper Lillooet River, Boulder Creek, Tretheway Creek, Big Silver Creek and Mesgi'g Ugju's'n Development Projects. Upon the closing of each fixed-rate or interest-swapped long-term financing, the Corporation will settle the corresponding derivative financial instruments, which will result in a realized gain or loss on derivative financial instruments. These gains or losses will serve to offset a higher or lower interest rate on the project-level debt. As at June 30, 2014, the derivatives to be settled upon closing of financing had a negative market value of $44.3 million.

Derivatives had a net negative value of $95.4 million at June 30, 2014 (negative $31.0 million at December 31, 2013). This variation is due mainly to a decrease in benchmark interest rates since the end of 2013. 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.

Accrual for Acquisition of Long-Term Assets

Accrual for acquisition of long-term assets consists of long-term debt commitments that have been secured and will be drawn to finance the Corporation's projects currently under construction or under development. As at June 30, 2014, accrual for acquisition of long-term assets totalled $42.4 million ($9.9 million as at December 31, 2013). The $32.6 million increase results mainly from expenses accruing for the Tretheway Creek, Boulder Creek, Upper Lillooet River and Big Silver Creek projects currently under construction.

Long-Term Debt

As at June 30, 2014, long-term debt totalled $1,444 million ($1,340 million as at December 31, 2013). The $103.2 million increase in long-term debt results mainly from the addition of the SM-1 debts in the amount of $78.4 million and from drawings under the revolving term credit facility to fund construction costs of the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek projects and pre-construction development costs of the Mesgi'g Ugju's'n project until the project-level financing for each of these projects is secured and the revolving term credit facility can be paid down. This increase was partly offset by the scheduled repayment of project-level debts and the reduction of drawings under the revolving term credit facility with the reimbursement of the $25.0 million loan to the seller of SM-1, plus accrued interest of $3.5 million. The SM-1 debts consist of $37.5 million in project-level debt carrying an interest rate of 3.3% and a $40.9 million debenture carrying an interest rate of 8.0%. The amount of project-level debt for the SM-1 hydroelectric facility reflects its adjustment to fair market value upon consolidation.

Since the beginning of the 2014 fiscal year, the Corporation and its subsidiaries have met all the financial and non-financial conditions related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements or trust indentures entered into by various subsidiaries of the Corporation could limit the capacity of these subsidiaries to transfer funds to the Corporation. These restrictions could have a negative impact on the Corporation's ability to meet its obligations.

Shareholders' Equity

As at June 30, 2014, the Coroporation's shareholders' equity totalled $622.2 million, including $59.9 million of non-controlling interests, compared with $665.9 million, including $81.4 million of non-controlling interests, as at December 31, 2013. This $43.7 million decrease in total shareholders' equity is attributable mainly to the recognition of a $52.3 million net loss and to dividends declared on preferred and common shares of $33.0 million, partly offset by the issuance to the seller of SM-1 of 4,027,051 common shares of the Corporation at a price of $10.36 per share to pay for the acquisition of the SM-1 hydroelectric facility, giving total net proceeds of $41.7 million.

Off-Balance-Sheet Arrangements

As at June 30, 2014, the Corporation had issued letters of credit totalling $44.4 million to meet its obligations under its various PPAs and other agreements. Of this amount, $32.2 million was issued under its revolving term credit facility and the remainder under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $11.0 million in corporate guarantees to support the construction of the Gros-Morne wind farm and the performance of the Brown Lake hydroelectric facility.

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

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 operations 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 derivate financial instruments used to hedge the interest rate on project-level debt prior to securing such debt.

Free Cash Flow and Payout Ratio calculation	Trailing 12-months ended June 30	
	2014	2013
Cash flows from operating activities	93,959	105,626
(Subtract) Add the following items:		
Changes in non-cash operating working capital items	(7,276)	(32,909)
Maintenance capital expenditures net of proceeds from disposals	(2,558)	(2,804)
Scheduled debt principal payments	(27,694)	(23,997)
Free Cash Flow attributed to non-controlling interests[1]	(1,550)	(7,806)
Dividends declared on Preferred shares	(7,126)	(5,954)
Cash receipt for wheeling services to be provided by the Harrison Hydro L.P. to other facilities[2]	—	4,916
Adjust for the following elements:		
Transaction costs related to realized acquisitions	592	2,345
Realized losses on derivative financial instruments	—	17,386
Free Cash Flow	48,347	56,803
Dividends declared on common shares	57,039	54,441
Payout Ratio - before the impact of the DRIP	118%	96%
Dividends declared on common shares and paid in cash[3]	44,184	39,055
Payout Ratio - after the impact of the DRIP	91%	69%

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. The $4.9 million represents a cash receipt by the Harrison Hydro L.P. for the wheeling services to be provided to the Northwest Stave River facility, 49.99% of which was included in the Free Cash Flow attributed to non-controlling interests.
3. Represents dividends declared on common shares outstanding that were not registered in the DRIP at the time of the declaration; the dividends declared on common shares registered in the DRIP were paid in common shares.

For the trailing 12-month period ended June 30, 2014, the Corporation generated Free Cash Flow of $48.3 million, compared with $56.8 million for the same period last year. This decrease is due mainly to the greater scheduled debt principal payments and to lower cash flows from operating activities, before changes in non-cash operating working capital items and realized losses on derivative financial instruments, attributable mainly to production being below the long-term average over a longer period during the trailing 12-month period ended June 30, 2014, compared with the same period last year.

Payout Ratio

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

For the trailing 12-month period ended June 30, 2014, the dividends on common shares declared by the Corporation corresponded to 118% of Free Cash Flow, compared with 96% for the corresponding prior 12-month period. The negative variation is due mainly to the decrease in Free Cash Flow explained above as well as to the increase in dividends declared on common shares resulting from the higher number of shares outstanding by virtue of the DRIP and from the issuance of 4,027,051 common shares of the Corporation to pay for the acquisition of the SM-1 hydroelectric facility.

The Payout Ratio reflects the Corporation's decision to invest each year in advancing the development of its Prospective Projects, which investments must be expensed as incurred. The Corporation considers such investments essential to its long-term growth and success, as it believes that the greenfield development of renewable energy projects offers the greatest potential internal rates of return and represents the most efficient use of management's expertise and value-added skills. For the trailing 12-month period ended June 30, 2014, the Corporation incurred prospective project expenses of $5.2 million, compared with $4.2 million for the corresponding prior 12-month period. This 24% increase is attributable mainly to the current request for proposals in Quebec and the upcoming request for proposals in Ontario. Excluding these discretionary expenses, the Corporation's Payout Ratio would be approximately 11 percentage points lower for the trailing 12-month period ended June 30, 2014, and approximately seven percentage points lower for the corresponding prior 12-month period.

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

SEGMENT INFORMATION

Geographic Segments

As at June 30, 2014, the Corporation had interests in 25 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the the three- and six-month periods ended June 30, 2014, the revenues generated by the Horseshoe Bend hydroelectric facility in the United States totalled $1.4 million and $1.8 million respectively ($1.2 million and $1.5 million respectively in 2013), corresponding to contributions of 2.0% and 1.6% respectively (2.0% and 1.5% respectively in 2013) to the Corporation's consolidated revenues for these periods. The increase is due mainly to improved water flows and higher selling prices, compared with the same periods last year.

Operating Segments

As at June 30, 2014, 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, 2013. 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 June 30, 2014	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	767,756	116,747	14,219	—	898,722
Revenues	54,348	9,329	5,972	—	69,649
Expenses:					
Operating expenses	8,545	2,208	272	—	11,025
General and administrative expenses	2,175	645	82	428	3,330
Prospective project expenses	—	—	—	1,477	1,477
Adjusted EBITDA	43,628	6,476	5,618	(1,905)	53,817
Three-months ended June 30, 2013					
Power generated (MWh)	638,994	140,551	12,997	—	792,542
Revenues	46,611	11,097	5,459	—	63,167
Expenses:					
Operating expenses	5,567	2,403	289	—	8,259
General and administrative expenses	1,795	615	53	461	2,924
Prospective project expenses	—	—	—	724	724
Adjusted EBITDA	39,249	8,079	5,117	(1,185)	51,260

SUMMARY OPERATING RESULTS Six-months ended June 30, 2014	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	954,325	339,973	21,633	—	1,315,931
Revenues	71,067	27,095	9,086	—	107,248
Expenses:					
Operating expenses	13,605	4,478	587	—	18,670
General and administrative expenses	4,332	1,526	165	861	6,884
Prospective project expenses	—	—	—	2,548	2,548
Adjusted EBITDA	53,130	21,091	8,334	(3,409)	79,146
Six-months ended June 30, 2013					
Power generated (MWh)	815,552	343,227	19,932	—	1,178,711
Revenues	63,185	27,298	8,372	—	98,855
Expenses:					
Operating expenses	9,644	4,473	600	—	14,717
General and administrative expenses	3,643	1,210	171	902	5,926
Prospective project expenses	—	—	—	1,549	1,549
Adjusted EBITDA	49,898	21,615	7,601	(2,451)	76,663

SUMMARY BALANCE SHEET As at June 30, 2014	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	—	—	—	8,269
Total assets	1,750,213	371,899	126,216	272,430	2,520,758
Total liabilities	1,254,876	243,080	115,599	284,966	1,898,521
Acquisition of property, plant and equipment during the period	1,324	196	161	78,394	80,075
As at December 31, 2013					
Goodwill	8,269	—	—	—	8,269
Total assets	1,449,527	387,062	128,146	412,339	2,377,074
Total liabilities	949,570	248,594	116,085	396,890	1,711,139
Acquisition of property, plant and equipment during the year	66,581	1,213	100	89,501	157,395

Hydroelectric Generation Segment

For the three-month period ended June 30, 2014, this segment produced 98% of the LTA and generated revenues of $54.3 million, compared with production at 104% of the LTA and revenues of $46.6 million for the same period last year. Water flows were above average in Quebec and the United States, below average in Ontario and slightly below average in British Columbia at 97% of the LTA.

For the six-month period ended June 30, 2014, this segment produced 90% of the LTA and generated revenues of $71.1 million, compared with production at 96% of the LTA and revenues of $63.2 million for the same period last year. This level of production stems mainly from the impact of below-average water flows during the first quarter, especially in British Columbia.

The revenue increase of 17% in the second quarter and 12% for the first half of 2014 stem mainly from the addition of the Magpie hydroelectric facility acquired in July 2013 and the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013. The SM-1 facility acquired in June 2014 contributed only marginally to operating results.

The increase in total assets since December 31, 2013, is attributable mainly to the increase in property, plant and equipment relating to the transfer of the Kwoiek Creek facility from the Site Development segment and the addition of the SM-1 facility acquired in June 2014, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2013, is attributable mainly to the transfer of the Kwoiek Creek loan from the Site Development segment and the addition of the SM-1 facility, partly offset by the scheduled repayment of long-term debt.

Wind Power Generation Segment

For the three-month period ended June 30, 2014, this segment produced 82% of the LTA and generated revenues of $9.3 million, compared with production at 98% of the LTA and revenues of $11.1 million for the same period last year. This level of production stems mainly from below-average wind regimes at all wind farms during the quarter. The 16% decrease in revenues stems mainly from production levels that were lower than for the same period last year.

For the six-month period ended June 30, 2014, this segment produced 95% of the LTA and generated revenues of $27.1 million, compared with production at 96% of the LTA and revenues of $27.3 million for the same period last year. This level of production stems mainly from below-average wind regimes during the second quarter, which more that offset above-average wind regimes during the first quarter.

The decrease in total assets since December 31, 2013, is attributable mainly to depreciation of property, plant and equipment and amortization of intangible assets.

The decrease in total liabilities since December 31, 2013, is attributable mainly to the scheduled repayment of long-term debt.

Solar Power Generation Segment

For the three-month period ended June 30, 2014, this segment produced 113% of the LTA and generated revenues of $6.0 million, compared with production at 103% of the LTA and revenues of $5.5 million for the same period last year. This production level stems mainly from above average solar regimes during the quarter. The 9% increase in revenues stems mainly from production levels that were greater than for the same period last year.

For the six-month period ended June 30, 2014, this segment produced 109% of the LTA and generated revenues of $9.1 million, compared with production at 99% of the LTA and revenues of $8.4 million for the same period last year. Solar irradiation was average during the first quarter and above average during the second quarter. The 9% increase in revenues is due mainly to higher production levels than for the same period last year, at least in part due to unusually large snowfalls and snow removal activities hampered by cold weather during the first quarter of 2013.

The decrease in total assets since December 31, 2013, results mainly from depreciation of property, plant and equipment as well as amortization of intangible assets.

The decrease in total liabilities since December 31, 2013, results mainly from scheduled repayment of long-term debt.

Site Development Segment

For the three- and six-month periods ended June 30, 2014, site development expenses were $1.9 million and $3.4 million respectively, compared with $1.2 million and $2.5 million respectively in 2013. The increase during these periods is due mainly to higher prospective project expenses related to the current request for proposals in Quebec and the upcoming request for proposals in Ontario.

The decrease in total assets since December 31, 2013, is attributable mainly to the transfer of the Kwoiek Creek facility to the hydroelectric generation segment, partly offset by payments made for costs incurred for the construction of the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek projects and pre-construction activities of the Mesgi'g Ugju's'n project.

The decrease in total liabilities since December 31, 2013, is attributable mainly to the transfer of the Kwoiek Creek loan to the hydroelectric generation segment, partly offset by the increase in derivative financial instruments following the Corporation's completion of the hedging program to fix the interest rate on future project-level debt for its Development Projects.

QUARTERLY FINANCIAL INFORMATION

	Three-months ended			
(in millions of dollars, unless otherwise stated)	June 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Sept. 30, 2013
Power generated (MWh)	898,722	417,209	496,613	706,495
Revenues	69.6	37.6	41.4	58.0
Adjusted EBITDA	53.8	25.3	25.6	46.7
Unrealized net loss (gain) on derivative financial instruments	29.1	36.0	(11.7)	(2.4)
Net (loss) earnings	(14.2)	(38.1)	3.4	11.1
Net (loss) earnings attributable to owners of the parent	(7.8)	(27.4)	6.3	10.8
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.10)	(0.30)	0.05	0.09
Dividends declared on preferred shares	1.8	1.8	1.8	1.8
Dividends declared on common shares	15.0	14.4	13.9	13.8
Dividends declared on common shares, $ per share	0.15	0.15	0.145	0.145

	Three-months ended			
(in millions of dollars, unless otherwise stated)	June 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Sept. 30, 2012
Power generated (MWh)	792,541	386,171	531,564	559,379
Revenues	63.2	35.7	47.1	47.1
Adjusted EBITDA	51.3	25.4	34.2	36.7
Unrealized net (gain) loss on derivative financial instruments	(27.3)	(3.8)	(5.3)	(9.5)
Net earnings (loss)	31.0	(0.2)	(0.6)	(0.7)
Net earnings (loss) attributable to owners of the parent	28.3	2.8	1.8	(0.2)
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.28	0.01	0.00	(0.01)
Dividends declared on preferred shares	1.8	2.0	1.1	1.1
Dividends declared on common shares	13.7	13.6	13.6	13.5
Dividends declared on common shares, $ per share	0.145	0.145	0.145	0.145

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 77% 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 change in the market value of derivative financial instruments. Historical analysis of net earnings (loss) should therefore take this factor into account. It is important to bear in mind that changes in the 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.

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

INVESTMENTS IN JOINT VENTURES

The Corporation's material joint ventures at the end of the reporting period were Umbata Falls Limited Partnership ("Umbata Falls, L.P.") (49% interest) and Parc éolien communautaire Viger-Denonville, s.e.c. (Viger-Denonville, L.P.) (50% interest).

A summary of the electricity production and financial information for the Corporation's material joint ventures is presented below. The summarized financial information corresponds to amounts shown in the joint ventures' financial statements prepared in accordance with IFRS.

Electricity Production

Three months ended June 30	2014				2013			
	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	42,310	37,823	112%	84.56	39,416	37,823	104%	84.38
Viger-Denonville	14,081	15,450	91%	148.55	—	—	—	—

Six months ended June 30	2014				2013			
	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	61,083	54,750	112%	84.32	58,257	54,750	106%	84.35
Viger-Denonville	37,366	35,750	105%	148.55	—	—	—	—

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

Umbata Falls, L.P.

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

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Revenues	3,578	3,324	5,150	4,914
Operating and general and administrative expenses	222	186	413	367
Adjusted EBITDA	3,356	3,138	4,737	4,547
Finance costs	610	631	1,221	1,242
Other net revenues	(9)	(8)	(21)	(16)
Depreciation and amortization	1,003	1,007	2,007	2,013
Unrealized net loss (gain) on derivative financial instruments	641	(2,958)	2,140	(3,418)
Net earnings (loss) and comprehensive income (loss)	1,111	4,466	(610)	4,726

For the three- and six-month periods ended June 30, 2014, production was above-average thanks to above-average water flows, similar to last year. Revenues and Adjusted EBITDA were slightly greater than for the same periods last year. The lower net earnings for the three-month period and the net loss in the six-month period are attributable to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the end of 2013, compared with an unrealized net gain on derivative financial instruments resulting from the increase in benchmark interest rates during the same periods last year.

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

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

As at	June 30, 2014	December 31, 2013
Current assets	3,619	3,685
Non-current assets	73,870	75,864
Current liabilities	47,432	47,972
Non-current liabilities	4,012	1,852
Partners' equity	26,045	29,725

The reduction in partners' equity stems mainly from a distribution of $3.1 million and to the net loss generated for the six-month period. In addition, the July 2014 term maturity of the Umbata Falls loan, which has been recorded in the current portion of long-term debt, has been extended by a few months. Umbata Falls, L.P. expects to refinance the outstanding balance before the end of the year. Also, Umbata Falls, 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 Derivatives for speculation purposes. An interest-rate swap totalling $46.1 million used to hedge the interest rate on 100% of the Umbata Falls loan had a net negative value of $5.2 million at June 30, 2014 (negative $3.0 million at December 31, 2013).

Viger-Denonville, L.P.

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

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Revenues	2,092	—	5,551	—
Operating and general and administrative expenses	424	2	965	4
Adjusted EBITDA	1,668	(2)	4,586	(4)
Finance costs	829	—	1,668	—
Other net revenues	(10)	(897)	(16)	(897)
Depreciation and amortization	835	1	1,671	1
Unrealized net loss (gain) on derivative financial instruments	693	(2,392)	2,250	(1,888)
Net (loss) earnings and comprehensive (loss) income	(679)	3,286	(987)	2,780

For the three- and six-month periods ended June 30, 2014, revenues and Adjusted EBITDA reflect the operation of the Viger-Denonville wind farm, which was commissioned in November 2013. The net loss generated during these periods is attributable to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the end of 2013, compared with an unrealized net gain on derivative financial instruments resulting from the increase in benchmark interest rates during the same periods last year.

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

As at	June 30, 2014	December 31, 2013
Current assets	19,518	9,221
Non-current assets	65,426	63,940
Current liabilities	12,543	8,200
Non-current liabilities	57,759	44,813
Partners' equity	14,643	20,148

The reduction in partners' equity stems mainly from a reimbursement of equity investment of $4.5 million once the project financing was in place and to the net loss generated for the six-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 Derivatives for speculation purposes. An interest-rate swap totalling $57.9 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $3.1 million at June 30, 2014 (negative $0.9 million at December 31, 2013).

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

NON-WHOLLY OWNED SUBSIDIARIES

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

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

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

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Revenues	19,308	21,007	23,706	25,861
Adjusted EBITDA	16,002	18,628	18,206	21,366
Net earnings (loss) and comprehensive income (loss)	561	4,890	(8,011)	(754)
Net earnings (loss) and comprehensive income (loss) attributable to:				
Owners of the parent	134	2,296	(4,294)	(669)
Non-controlling interests	427	2,594	(3,717)	(85)
	561	4,890	(8,011)	(754)

For the three- and six-month periods ended June 30, 2014, the decrease in revenues and Adjusted EBITDA is due mainly to lower production levels compared with the same periods last year, which have remained below the LTA as a result of below-average water flows in British Columbia. The lower net earnings for the quarter and greater net loss for the six-month period are also attributable to greater inflation compensation interest on the real return bonds of $4.9 million for the quarter and $5.1 million for the six-month period ($3.3 million and of $1.2 million respectively for the same periods last year) as a result of higher inflation.

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

As at	June 30, 2014	December 31, 2013
Current assets	23,878	30,143
Non-current assets	654,124	662,749
Current liabilities	18,882	13,925
Non-current liabilities	462,278	460,511
Equity attributable to owners	119,398	130,497
Non-controlling interests	77,444	87,959

As at June 30, 2014, the decrease in non-current assets is due mainly to depreciation of fixed assets. Furthermore, Harrison Hydro L.P. distributed $13.6 million in 2013. The distribution was made in the form of non-interest bearing loans of $6.8 million each to the Corporation and its partners, which were presented as loans to partners at December 31, 2013. On January 1, 2014, these loans were reimbursed directly from distributions from Harrison Hydro L.P., and a corresponding decrease in non-controlling interests was recorded in 2014 with no impact to cash flows.

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

Creek Power Inc. and Its Six Subsidiaries

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

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Revenues	839	858	842	868
Adjusted EBITDA	435	413	(54)	34
Net (loss) earnings and comprehensive (loss) income	(9,185)	472	(22,682)	(358)
Net (loss) earnings and comprehensive (loss) income attributable to:				
Owners of the parent	(6,105)	320	(15,099)	(226)
Non-controlling interest	(3,079)	152	(7,583)	(132)
	(9,184)	472	(22,682)	(358)

For the three- and six-month periods ended June 30, 2014, the recognition of a net loss is due mainly to the recognition during the quarter of an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the beginning of the quarter, compared with an unrealized net gain for the same period last year, and to the recognition during the six-month period of a greater unrealized net loss on derivative financial instruments, compared with the same period last year.

Summary Statements of Financial Position – Creek Power Inc.

As at	June 30, 2014	December 31, 2013
Current assets	2,721	6,593
Non-current assets	133,282	67,349
Current liabilities	39,843	13,547
Non-current liabilities	127,981	69,534
Deficit attributable to owners	(24,996)	(9,897)
Non-controlling interest	(6,825)	758

The increase in balance sheet items is due mainly to construction spending for the Upper Lillooet River and Boulder Creek projects. The increase in current liabilities is also due to the bond forward contracts entered into to hedge the interest rate on future project-level financing for these projects.

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

Kwoiek Creek Resources Limited Partnership and Its General Partner

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

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Revenues	4,767	—	5,143	—
Adjusted EBITDA	3,885	(2)	3,732	(5)
Net loss and comprehensive loss	(1,564)	(2)	(5,488)	(5)
Net loss and comprehensive loss attributable to:				
Owners of the parent	(684)	(1)	(2,578)	(2)
Non-controlling interest	(880)	(1)	(2,910)	(3)
	(1,564)	(2)	(5,488)	(5)

For the three- and six-month periods ended June 30, 2014, revenues and Adjusted EBITDA reflect the operation of the Kwoiek Creek hydroelectric facility, which was commissioned effective January 1, 2014. The net loss generated during these periods is due mainly to production levels below the LTA as a result of below-average water flows in British Columbia and commissioning activities, as operating expenses, depreciation and finance costs are not directly correlated to production levels.

Summary Statements of Financial Position – Kwoiek Creek Resources Limited Partnership

As at	June 30, 2014	December 31, 2013
Current assets	22,108	34,019
Non-current assets	177,700	177,928
Current liabilities	6,566	23,694
Non-current liabilities	213,378	202,901
Deficit attributable to owners	(10,092)	(7,514)
Non-controlling interests	(10,044)	(7,134)

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

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

The Mesgi'g Ugju's'n subsidiary began operating on March 21, 2014.

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

	Three months ended June 30, 2014	Since March 21, 2014
Revenues	—	—
Adjusted EBITDA	—	—
Net loss and comprehensive loss	(5,795)	(5,674)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(2,992)	(2,871)
Non-controlling interest	(2,803)	(2,803)
	(5,795)	(5,674)

For the three-month ended June 30, 2014, and since the subsidiary began operations in March 2014, the recognition of a net loss is due mainly to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the beginning of these periods.

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

As at	June 30, 2014
Current assets	732
Non-current assets	4,757
Current liabilities	6,163
Non-current liabilities	—
Deficit attributable to owners	(171)
Non-controlling interest	(503)

The increase in balance sheet items is due mainly to a transfer by the partner of $2.3 million in assets in exchange for an equity investment in the same amount, with no impact on cash flows.

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

Innergex Sainte-Marguerite, S.E.C. ("SM-1 L.P.") and Its General Partner

On June 20, 2014, the Corporation signed an asset purchase agreement for the acquisition of the SM-1 hydroelectric facility.

Summary Statements of Earnings and Comprehensive Income – SM-1 L.P.

	Period of 11 days ended June 30, 2014
Revenues	283
Adjusted EBITDA	249
Net loss and comprehensive loss	(52)
Net loss and comprehensive loss attributable to:	
Owners of the parent	(26)
Non-controlling interest	(26)
	(52)

Summary Statements of Financial Position – SM-1 L.P.

As at	June 30, 2014
Current assets	3,822
Non-current assets	135,019
Current liabilities	4,980
Non-current liabilities	75,161
Equity attributable to owners	58,721
Non-controlling interests	(21)

ACCOUNTING CHANGES

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

IFRIC 21 Levies

In May 2013, the International Accounting Standards Board (”IASB”) issued IFRIC 21 – Levies (“IFRIC 21”), an interpretation of IAS 37 – Provisions, Contingent Liabilities and Contingent Assets (“IAS 37”), on the accounting for levies imposed by governments. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event (“obligating event”). IFRIC 21 clarifies that the obligating event that gives rise to a liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. This standard have been adopted and applied in these financial statements. The application of this standard has not had any material impact on the amounts reported for the current year.

New and revised IFRS issued but not yet effective

IFRS 15- Revenue from contracts with customers

In May 2014, IASB issued IFRS 15– Revenue from contracts with customers (“IFRS 15”). This standard replaces IAS 11 construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the construction of real estate, IFRIC 18 Transfers of assets from customers, and SIC-31 Revenue Barter transactions involving advertising services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2017. The Corporation is evaluating the impact the interpretation is expected to have on its consolidated financial statements.

IFRS 11- Joint arrangement

IFRS 11 was amended in May 2014 to add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. The Corporation is evaluating the impact the amendments are expected to have on its consolidated financial statements.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

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

		Three months ended June 30		Six months ended June 30	
		2014	2013	2014	2013
	Notes				
Revenues		69,649	63,167	107,248	98,855
Expenses					
Operating	4	11,025	8,259	18,670	14,717
General and administrative		3,330	2,924	6,884	5,926
Prospective projects		1,477	724	2,548	1,549
Earnings before finance costs, income taxes, depreciation, amortization, other net (revenues) expenses, share of (earnings) loss of joint ventures and unrealized net loss (gain) on derivative financial instruments		53,817	51,260	79,146	76,663
Finance costs	5	24,469	18,826	44,133	31,778
Other net (revenues) expenses	6	(739)	2,958	(912)	585
Earnings before income taxes, depreciation, amortization, share of (earnings) loss of joint ventures and unrealized net loss (gain) on derivative financial instruments		30,087	29,476	35,925	44,300
Depreciation	4,8	13,679	11,999	27,338	24,008
Amortization	4	5,252	5,453	10,440	10,905
Share of (earnings) loss of joint ventures		(204)	(3,832)	792	(3,706)
Unrealized net loss (gain) on derivative financial instruments		29,147	(27,318)	65,177	(31,156)
(Loss) earnings before income taxes		(17,787)	43,174	(67,822)	44,249
(Recovery of) income tax expense					
Current		845	854	1,596	1,658
Deferred		(4,443)	11,281	(17,124)	11,730
		(3,598)	12,135	(15,528)	13,388
Net (loss) earnings		(14,189)	31,039	(52,294)	30,861
Net (loss) earnings attributable to:					
Owners of the parent		(7,835)	28,302	(35,254)	31,099
Non-controlling interests		(6,354)	2,737	(17,040)	(238)
		(14,189)	31,039	(52,294)	30,861
Weighted average number of common shares outstanding (in 000s)	7	96,513	94,370	96,172	94,142
Basic net (loss) earnings per share ($)	7	(0.10)	0.28	(0.40)	0.29
Diluted weighted average number of common shares outstanding (in 000s)	7	96,714	94,433	96,351	94,219
Diluted net (loss) earnings per share ($)	7	(0.10)	0.28	(0.40)	0.29

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

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

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Net (loss) earnings	(14,189)	31,039	(52,294)	30,861
Items of comprehensive (loss) income that will be subsequently reclassified to profit or loss:				
Foreign exchange (loss) gain on translation of self-sustaining foreign subsidiaries	(238)	183	3	279
Related deferred tax	31	(24)	(1)	(36)
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	247	(187)	3	(286)
Related deferred tax	(32)	24	—	37
Other comprehensive income (loss)	8	(4)	5	(6)
Total comprehensive (loss) income	(14,181)	31,035	(52,289)	30,855
Total comprehensive (loss) income attributable to:				
Owners of the parent	(7,827)	28,298	(35,249)	31,093
Non-controlling interests	(6,354)	2,737	(17,040)	(238)
	(14,181)	31,035	(52,289)	30,855

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	June 30, 2014	December 31, 2013
Assets			
Current assets			
Cash and cash equivalents		27,516	34,267
Restricted cash and short-term investments		26,994	49,745
Accounts receivable		42,147	19,799
Reserve accounts		1,199	1,771
Income tax receivable		66	80
Derivative financial instruments		1,417	7,563
Loans to related parties	14	—	6,798
Prepaid and others		6,349	5,085
		105,688	125,108
Reserve accounts		44,910	45,791
Property, plant and equipment	8	1,768,699	1,583,417
Intangible assets		498,111	466,093
Project development costs		55,284	81,643
Investments in joint ventures		20,084	24,639
Derivative financial instruments		5,204	7,066
Deferred tax assets		8,133	1,804
Goodwill		8,269	8,269
Other long-term assets	3	6,376	33,244
		2,520,758	2,377,074

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	June 30, 2014	December 31, 2013
Liabilities			
Current liabilities			
Dividends payable to shareholders		16,794	15,651
Accounts payable and other payables		32,110	48,258
Income tax liabilities		1,306	2,216
Derivative financial instruments		56,939	12,915
Current portion of long-term debt		32,733	26,649
Current portion of other liabilities		370	362
		140,252	106,051
Construction holdbacks		5,668	1,347
Derivative financial instruments		39,226	26,081
Accrual for acquisition of long-term assets		42,421	9,855
Long-term debt	9	1,410,862	1,313,718
Other liabilities		10,762	10,567
Liability portion of convertible debentures		79,923	79,831
Deferred tax liabilities		169,407	163,689
		1,898,521	1,711,139
Shareholders' equity			
Common shares capital	10	56,282	10,374
Contributed surplus from reduction of capital on common shares		784,482	784,482
Preferred shares		131,069	131,069
Share-based payment		1,937	1,806
Equity portion of convertible debentures		1,340	1,340
Deficit		(413,018)	(344,809)
Accumulated other comprehensive income		249	244
Equity attributable to owners		562,341	584,506
Non-controlling interests		59,896	81,429
Total shareholders' equity		622,237	665,935
		2,520,758	2,377,074

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners											
For the six-month period ended June 30, 2014	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 income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2014	95,655	10,374	784,482	131,069	1,806	1,340	(344,809)	244	584,506	81,429	665,935
Net loss							(35,254)		(35,254)	(17,040)	(52,294)
Other items of comprehensive income								5	5		5
Total comprehensive (loss) income	—	—	—	—	—	—	(35,254)	5	(35,249)	(17,040)	(52,289)
Common shares issued on June 20, 2014 : private placement (Note 3)	4,027	41,720							41,720		41,720
Issuance fees		(11)							(11)		(11)
Common shares issued through dividend reinvestment plan	404	4,199							4,199		4,199
Share-based payment					131				131		131
Distributions to non-controlling interests (Note 14)									—	(6,798)	(6,798)
Investments from non-controlling interests									—	2,305	2,305
Dividends declared on common shares							(29,392)		(29,392)		(29,392)
Dividends declared on preferred shares							(3,563)		(3,563)		(3,563)
Balance June 30, 2014	100,086	56,282	784,482	131,069	1,937	1,340	(413,018)	249	562,341	59,896	622,237

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
For the six-month period ended June 30, 2013	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 income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2013	93,660	120,500	656,281	131,069	1,511	1,340	(330,621)	241	580,321	107,611	687,932
Net earnings (loss)							31,099		31,099	(238)	30,861
Other items of comprehensive loss								(6)	(6)		(6)
Total comprehensive income (loss)	—	—	—	—	—	—	31,099	(6)	31,093	(238)	30,855
Common shares issued through dividend reinvestment plan	790	7,702							7,702		7,702
Reduction of capital on common shares		(128,201)	128,201						—		—
Share-based payment					171				171		171
Distributions to non-controlling interests (Note 14)									—	(23,444)	(23,444)
Dividends declared on common shares							(27,320)		(27,320)		(27,320)
Dividends declared on preferred shares							(3,828)		(3,828)		(3,828)
Balance June 30, 2013	94,450	1	784,482	131,069	1,682	1,340	(330,670)	235	588,139	83,929	672,068

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Six months ended June 30	
		2014	2013
	Notes		
Operating activities			
Net (loss) earnings		(52,294)	30,861
Items not affecting cash:			
Depreciation		27,338	24,008
Amortization		10,440	10,905
Share of loss (earnings) of joint ventures		792	(3,706)
Unrealized net loss (gain) on derivative financial instruments		65,177	(31,156)
Inflation compensation interest	5	5,093	1,184
Amortization of financing fees	5	498	462
Amortization of revaluation of long-term debt and convertible debentures	5	770	781
Accretion expenses on other liabilities	5	316	251
Share-based payment		131	171
Deferred income taxes		(17,124)	11,730
Effect of exchange rate fluctuations		19	327
Others		284	(41)
Interest on long-term debt and convertible debentures	5	37,084	28,938
Interest paid		(36,759)	(28,933)
Distributions received from joint ventures		1,504	1,040
Current income tax expense		1,596	1,658
Net income taxes paid		(2,493)	(783)
		42,372	47,697
Changes in non-cash operating working capital items	12	(22,715)	289
		19,657	47,986
Financing activities			
Dividends paid on common shares		(24,050)	(19,504)
Dividends paid on preferred shares		(3,562)	(3,111)
Increase of long-term debt		131,166	121,414
Repayment of long-term debt		(71,639)	(78,767)
Payment of deferred financing costs		(157)	(2,746)
Payment of other liabilities		(113)	—
Payment of issuance cost of common and preferred shares		(11)	(353)
		31,634	16,933

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Six months ended June 30	
		2014	2013
	Notes		
Investing activities			
Business acquisitions	3	(37,901)	—
Decrease of restricted cash and short-term investments		22,751	2,825
Loans to related parties	14	—	(13,452)
Net funds withdrawn from (invested into) the reserve accounts		1,715	(73)
Additions to property, plant and equipment		(58,273)	(51,811)
Additions to intangible assets		—	(28)
Additions to project development costs		(15,494)	(10,229)
Withdrawals from (Investments in) joint ventures		2,259	(5,484)
Investment from non-controlling interest	13.3	5	—
Reductions (additions) to other long-term assets		26,868	(186)
Proceeds from disposal of property, plant and equipment		48	56
		(58,022)	(78,382)
Effects of exchange rate changes on cash and cash equivalents		(20)	31
Net decrease in cash and cash equivalents		(6,751)	(13,432)
Cash and cash equivalents, beginning of period		34,267	49,496
Cash and cash equivalents, end of period		27,516	36,064
Cash and cash equivalents is comprised of:			
Cash		19,478	29,408
Short-term investments		8,038	6,656
		27,516	36,064

Additional information is presented in Note 12.

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

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

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 August 7, 2014.

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

2.1 New IFRSs affecting the reported financial performance and financial position in the current year

IFRIC 21 - Levies

In May 2013, the International Accounting Standards Board ("IASB") issued IFRIC 21 – Levies ("IFRIC 21"), an interpretation of IAS 37 – Provisions, Contingent Liabilities and Contingent Assets ("IAS 37"), on the accounting for levies imposed by governments. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event ("obligating event"). IFRIC 21 clarifies that the obligating event that gives rise to a liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. This standard have been adopted and applied in these financial statements. The application of this standard has not had any material impact on the amounts reported for the current year.

2.2 New and revised IFRS issued but not yet effective

IFRS 15- Revenue from contracts with customers

In May 2014, IASB issued IFRS 15– Revenue from contracts with customers ("IFRS 15"). This standard replaces IAS 11 construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the construction of real estate, IFRIC 18 Transfers of assets from customers, and SIC-31 Revenue Barter transactions involving advertising services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2017. The Corporation is evaluating the impact the interpretation is expected to have on its consolidated financial statements.

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

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 Corporation is evaluating the impact the amendments are expected to have on its consolidated financial statements.

3. BUSINESS ACQUISITIONS

3.1 Acquisition of assets of Sainte-Marguerite-1

On June 20, 2014, the Corporation and the Desjardins Group Pension Plan ("Desjardins") finalized the acquisition of the Sainte-Marguerite-1 ("SM-1") run-of-river hydroelectric facility located in Quebec, Canada. The preliminary purchase price of the SM-1 facility was $82,121 plus assumption of $37,455 in non-recourse, project-level debt carrying a fixed interest rate of 3.30% and maturing in 2025 (see note 9).

The preliminary purchase price of $82,121, was paid as follows: $37,901 in cash, $2,500 by way of a holdback payable and $41,720 by the issuance of units of Innergex Sainte-Marguerite, S.E.C. (“SM-1 LP”) which the seller immediately transferred to the Corporation in exchange for 4,027,051 newly issued common shares of the Corporation at a price of $10.36 per common share. As a result, the Corporation now holds the preferred units of SM-1 LP that carry a preferred distribution rate of 10.5% until January 1, 2024 and 11.3% thereafter. In addition, the purchase price has been reduced by an amount of $1,661 to reflect the amount of net cash flows generated by the facility since January 1, 2014, and attributable to the purchasers. Consequently, the holdback payable has been reduced to $839, resulting in an adjusted purchase price of $80,460. Other adjustments may occur, namely after the capital improvement program has been completed.

The total preliminary purchase price has been calculated as follows:

Cash	37,901
Holdback payable	839
Shares issued	41,720
Total purchase price	80,460

The Corporation and Desjardins respectively own 50.01% and 49.99% of the common units of SM-1 LP. Concurrent with the acquisition of the SM-1 facility, Desjardins subscribed to a debenture issued by SM-1 LP for total proceeds of $40,901. This debenture carries an interest rate of 8.0%, has no predetermined repayment schedule and matures in 2064.

Upon closing of the acquisition, the seller used a portion of the cash proceeds to repay to the Corporation the $25,000 deposit it received in July 2012, plus accrued interest income of $3,464. This deposit and accrued interests were accounted in other long term assets.

All power generated from the facility is sold to Hydro Québec under Power Purchase Agreements expiring in 2017 and 2027.

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 SM-1 facility added an additional installed capacity of approximately 30.5 MW to the Corporation's portfolio of operational hydroelectric facilities.

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

The following table reflects the preliminary purchase price allocation:

Reserve account	259
Property, plant and equipment	115,547
Intangible assets	19,213
Current liabilities	(583)
Long-term debt	(37,455)
Deferred tax liabilities	(16,521)
Net assets acquired	80,460

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

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

If the acquisition had taken place on January 1, 2014, the consolidated revenues and net loss for the three-month period ended June 30, 2014 would have been $71,768 and $13,530 respectively and $112,571 and $50,218 for the six-month period ended June 30, 2014.

The amounts of revenues and net loss of SM-1 LP since June 20, 2014 included in the consolidated statement of earnings are $283 and $52 respectively for the 11 days ended June 30, 2014.

4. OPERATING EXPENSES

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Salaries	943	741	1,731	1,390
Insurance	591	498	1,158	986
Operation and maintenance	4,370	3,848	7,772	6,916
Property taxes and royalties	5,121	3,172	8,009	5,425
	11,025	8,259	18,670	14,717

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

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

5. FINANCE COSTS

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Interest on long-term debt and on convertible debentures	18,656	14,620	37,084	28,938
Inflation compensation interest	4,861	3,308	5,093	1,184
Amortization of financing fees	242	244	498	462
Amortization of revaluation of long-term debt and convertible debentures	376	364	770	781
Accretion expenses on other liabilities	161	128	316	251
Others	173	162	372	162
	24,469	18,826	44,133	31,778

6. OTHER NET REVENUES (EXPENSES)

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Transaction costs	258	165	258	276
Realized loss on derivative financial instruments	—	3,259	—	3,259
Realized (gain) loss on foreign exchange	(223)	195	33	261
Other net revenues	(774)	(661)	(1,203)	(1,211)
Settlement of claims received in relation with an acquisition	—	—	—	(2,000)
	(739)	2,958	(912)	585

7. COMPUTATION OF NET (LOSS) EARNINGS AVAILABLE TO COMMON SHAREHOLDERS

The net (loss) earnings attributable to owners of the parent are adjusted for the dividends on the preferred shares as follows:

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Net (loss) earnings attributable to owners of the parent	(7,835)	28,302	(35,254)	31,099
Dividends declared on preferred shares	(1,782)	(1,781)	(3,563)	(3,828)
Net (loss) earnings available to common shareholders	(9,617)	26,521	(38,817)	27,271
Weighted average number of common shares (in 000s)	96,513	94,370	96,172	94,142
Basic net (loss) earnings per share ($)	(0.10)	0.28	(0.40)	0.29
Weighted average number of common shares (in 000s)	96,513	94,370	96,172	94,142
Effect of dilutive elements on common shares (in 000s) (a)	201	63	179	77
Diluted weighted average number of common shares (in 000s)	96,714	94,433	96,351	94,219
Diluted net (loss) earnings per share ($) (b)	(0.10)	0.28	(0.40)	0.29

a. During the three-month period ended June 30, 2014, 1,243,000 of 3,073,684 stock options (2,073,420 of 2,736,684 for the three-month period ended June 30, 2013) and 7,558,684 shares which can be issued on conversion of convertible debentures (7,558,684 for the three-month period ended June 30, 2013) were excluded from the calculation of diluted weighted average number of shares outstanding as the exercise price was above the average market price of common shares.

During the six-month period ended June 30, 2014, 1,243,000 of 3,073,684 stock options (1,263,000 of 2,736,684 for the six-month period ended June 30, 2013) and 7,558,684 shares which can be issued on conversion of convertible debentures (7,558,684 for the six-month period ended June 30, 2013) were excluded from the calculation of diluted weighted average number of shares outstanding as the exercise price was above the average market price of common shares.

b. During the three-month and six-month periods ended June 30, 2014, 1,830,684 of 3,073,684 stock options (nil for the three-month and six-month periods ended June 30, 2013) were excluded from the calculation of diluted net loss per shares 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)

8. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2014	2,141	1,063,065	370,729	124,205	201,742	7,473	1,769,355
Additions	161	784	196	—	78,393	541	80,075
Business acquisitions (Note 3)	230	115,314	—	—	—	3	115,547
Transfer of assets upon commissioning	—	154,175	—	—	(154,175)	—	—
Transfer from projects under development	—	—	—	—	17,279	—	17,279
Dispositions	—	(298)	—	—	—	(68)	(366)
Other changes	—	(28)	—	—	—	(17)	(45)
Net foreign exchange differences	—	18	—	—	—	—	18
As at June 30, 2014	2,532	1,333,030	370,925	124,205	143,239	7,932	1,981,863
Accumulated depreciation							
As at January 1, 2014	—	(107,529)	(64,772)	(9,915)	—	(3,722)	(185,938)
Depreciation	—	(14,772)	(8,851)	(2,976)	—	(739)	(27,338)
Dispositions	—	31	—	—	—	47	78
Other changes	—	10	—	—	—	27	37
Net foreign exchange differences	—	(2)	—	—	—	(1)	(3)
As at June 30, 2014	—	(122,262)	(73,623)	(12,891)	—	(4,388)	(213,164)
Carrying amount as at June 30, 2014	2,532	1,210,768	297,302	111,314	143,239	3,544	1,768,699

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

Additions in the current cumulated period include $1,228 of capitalized financing costs ($13,359 for the year ended December 31, 2013) 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 $1,161 ($1,161 as at December 31, 2013).

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

9. LONG-TERM DEBT

a. Sainte-Marguerite

As part of the Sainte-Marguerite Acquisition, the Corporation assumed a $30,796 term loan, bearing interest at 7.4%, repayable in monthly blended payments of principal and interest totaling $360, increasing over the years and maturing in 2025. The term loan was accounted for at its fair market value of $37,455 for an effective rate of 3.30%.

The loan is secured by all SM-1 LP's assets with a carrying value of approximately $138,841.

Concurrent with the acquisition of the SM-1 facility, a debenture was issue by SM-1 LP to Desjardins Group Pension Plan for total proceeds of $40,901. This debenture carries an interest rate of 8.0%, has no predetermined repayment schedule and matures in 2064.

b. Montagne-Sèche

In May 2014, the Corporation has renegociated the loan to extend the maturity to June 2021. As at June 30, 2014, the loan bears interest at banker's acceptance rate plus an applicable margin.

10. SHAREHOLDERS' CAPITAL

a) Common shares

Details of common shares issued are shown in the Consolidated Statements of Changes in Shareholders' Equity.

11. DIVIDENDS

The following are the dividends paid by the Corporation during the year.

Record date	Payment date	Dividends per common share ($)	Dividends per Preferred Series A share ($)	Dividends per Preferred Series C share ($)
12/31/2013	1/15/2014	0.1450	0.3125	0.359375
3/31/2014	4/15/2014	0.1500	0.3125	0.359375
6/28/2014	7/15/2014	0.1500	0.3125	0.359375
		0.4450	0.9375	1.078125

12. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Six months ended June 30	
	2014	2013
Accounts receivable and income tax receivable	(22,300)	8,621
Prepaid and others	(1,266)	(1,276)
Accounts payable, other payables and income tax liabilities	851	(7,056)
	(22,715)	289

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

b. Additional information

	Six months ended June 30	
	2014	2013
Interest paid (including $1,040 capitalized interest ($3,230 in 2013))	37,799	32,163
Non-cash transactions		
in unpaid property, plant and equipment	21,759	4,899
in unpaid development costs	(3,634)	880
in unpaid intangible assets	—	(27)
in unpaid issuance costs of preferred shares	—	(353)
in unpaid financing fees	—	48
in common shares issued through dividend reinvestment plan	(4,199)	(7,702)
acquisition of assets for a project under development in exchange of the increase of a non-controlling interest in a subsidiary	(2,300)	—

13. SUBSIDIARIES

13.1 Mesgi'g Ugju's'n (MU) Wind Farm L.P. and Its General Partner

In March 2014, the Corporation and its Mi'gmaq partner signed a 20-year fixed-price Purchase Power Agreement. This project is for the construction and operation of a wind farm located in Québec. According to the agreement signed, the voting rights held by non-controlling interest is 50% even though the Corporation owns more than 50% of the economic interest in Mesgi'g Ugju's'n (MU) Wind Farm L.P.

The summarized financial information below represents amounts before intragroup eliminations.

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

As at	June 30, 2014
Summary Statement of Financial Position	
Current assets	732
Non-current assets	4,757
Current liabilities	6,163
Non-current liabilities	—
Deficit attributable to owners	(171)
Non-controlling interest	(503)

	Period of 101 days ended June 30, 2014
Summary Statement of Loss and Comprehensive loss	
Revenues	—
Expenses	5,674
Net loss and comprehensive loss	(5,674)
Net loss and comprehensive loss attributable to:	
Owners of the parent	(2,871)
Non-controlling interest	(2,803)
	(5,674)
Summary Statement of Cash Flows	
Net cash outflow from operating activities	(469)
Net cash inflow from financing activities	1,501
Net cash outflow from investing activities	(889)
Net increase in cash and cash equivalents	143

13.2 Financial support to structured entity

Based on the contractual arrangements between the Corporation and the other partner signed during the first quarter of 2014, the Corporation concluded that it has control over Mesgi'g Ugju's'n (MU) Wind Farm L.P.

The Corporation is responsible for financing equity required by the project. Mi'gmawei Mawiomi Resources L.P., the other partner, can participate in the financing of the equity for an amount up to a maximum of $10,000.

The Corporation invested a total of $2,700 in Mesgi'g Ugju's'n (MU) Wind Farm L.P. preferred units. This investment provides the Corporation with revenues in the form of preferred distributions. During the second quarter of the year 2014, the Mi'gmaq partner also invested an amount of $2,300 in preferred units of the Mesgi'g Ugju's'n (MU) Wind farm L.P.

Distributions on preferred units will subsequently be payable subject to the availability of gross revenues. The cumulated distributions on preferred units are payable before making any distributions on common units.

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

13.3 Innergex Sainte-Marguerite, S.E.C. ("SM-1 LP") and Its General Partner

On June 20, 2014, the Corporation has signed an asset purchase agreement for the acquisition of the SM-1 facility.

The Corporation owns 50.01% of the common units of SM-1 LP. Concurrent with the acquisition of the SM-1 facility, Desjardins subscribed to a debenture issued by SM-1 LP for total proceeds of $40,901. This debenture carries an interest rate of 8.0%, has no predetermined repayment schedule and matures in 2064.

In addition, Desjardins has invested an amount of $5 in participating units of SM-1 LP. This is reflected in the non-controlling interest account.

The summarized financial information below represents amounts before intragroup eliminations.

As at	June 30, 2014
Summary Statement of Financial Position	
Current assets	3,822
Non-current assets	135,019
Current liabilities	4,980
Non-current liabilities	75,161
Equity attributable to owners	58,721
Non-controlling interest	(21)

	Period of 11 days ended June 30, 2014
Summary Statement of Loss and Comprehensive loss	
Revenues	283
Expenses	335
Net loss and comprehensive loss	(52)
Net loss and comprehensive loss attributable to:	
Owners of the parent	(26)
Non-controlling interest	(26)
	(52)
Summary Statement of Cash Flows	
Net cash outflow from operating activities	(687)
Net cash inflow from financing activities	41,406
Net cash outflow from investing activities	(37,896)
Net increase in cash and cash equivalents	2,823

14. RELATED PARTY TRANSACTIONS

The Harrison Hydro L.P. distributed $13,600 in 2013. The funds were distributed in the form of non-interest bearing loans of $6,798 each to the Corporation and its partners, which were presented as loans to partners as at December 31, 2013. On January 1, 2014, the $6,798 loans were reimbursed directly from distributions from the Harrison Hydro L.P. and a corresponding decrease in non-controlling interests was recorded in 2014 with no impact to cash flows.

15. SEGMENT INFORMATION

Geographic segments

The Corporation owns interests in 25 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the three- and six-month periods ended June 30, 2014, revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $1,365 and $1,759 ($1,231 and $1,474 in 2013), representing a contribution of 2.0% and 1.6% (2.0% and 1.5% in 2013) 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, share of (earnings) loss of joint ventures and unrealized net (gain) loss 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)

Three-month period ended June 30, 2014					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	54,348	9,329	5,972	—	69,649
Expenses:					
Operating	8,545	2,208	272	—	11,025
General and administrative	2,175	645	82	428	3,330
Prospective projects	—	—	—	1,477	1,477
Earnings before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net loss on derivative financial instruments	43,628	6,476	5,618	(1,905)	53,817
Finance costs					24,469
Other net revenues					(739)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net loss on derivative financial instruments					30,087
Depreciation					13,679
Amortization					5,252
Share of earnings of joint ventures					(204)
Unrealized net loss on derivative financial instruments					29,147
Loss before incomes taxes					(17,787)

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

Three-month period ended June 30, 2013					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	46,611	11,097	5,459	—	63,167
Expenses:					
Operating	5,567	2,403	289	—	8,259
General and administrative	1,795	615	53	461	2,924
Prospective projects	—	—	—	724	724
Earnings before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on derivative financial instruments	39,249	8,079	5,117	(1,185)	51,260
Finance costs					18,826
Other net expenses					2,958
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on derivative financial instruments					29,476
Depreciation					11,999
Amortization					5,453
Share of earnings of joint ventures					(3,832)
Unrealized net gain on derivative financial instruments					(27,318)
Earnings before incomes taxes					43,174

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

Six-month period ended June 30, 2014 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	71,067	27,095	9,086	—	107,248
Expenses:					
Operating	13,605	4,478	587	—	18,670
General and administrative	4,332	1,526	165	861	6,884
Prospective projects	—	—	—	2,548	2,548
Earnings before finance costs, income taxes, depreciation, amortization, other net revenues, share of loss of joint ventures and unrealized net loss on derivative financial instruments	53,130	21,091	8,334	(3,409)	79,146
Finance costs					44,133
Other net revenues					(912)
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net loss on derivative financial instruments					35,925
Depreciation					27,338
Amortization					10,440
Share of loss of joint ventures					792
Unrealized net loss on derivative financial instruments					65,177
Loss before income taxes					(67,822)

As at June 30, 2014					
Goodwill	8,269	—	—	—	8,269
Total assets	1,750,213	371,899	126,216	272,430	2,520,758
Total liabilities	1,254,876	243,080	115,599	284,966	1,898,521
Acquisition of property, plant and equipment since the beginning of the year	1,324	196	161	78,394	80,075

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

Six-month period ended June 30, 2013 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	63,185	27,298	8,372	—	98,855
Expenses:					
Operating	9,644	4,473	600	—	14,717
General and administrative	3,643	1,210	171	902	5,926
Prospective projects	—	—	—	1,549	1,549
Earnings before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on derivative financial instruments	49,898	21,615	7,601	(2,451)	76,663
Finance costs					31,778
Other net expenses					585
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on derivative financial instruments					44,300
Depreciation					24,008
Amortization					10,905
Share of earnings of joint ventures					(3,706)
Unrealized net gain on derivative financial instruments					(31,156)
Earnings before income taxes					44,249

As at December 31, 2013					
Goodwill	8,269	—	—	—	8,269
Total assets	1,449,527	387,062	128,146	412,339	2,377,074
Total liabilities	949,570	248,594	116,085	396,890	1,711,139
Acquisition of property, plant and equipment during the year	66,581	1,213	100	89,501	157,395

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

16. SUBSEQUENT EVENTS

a. Dividends declared by the Board of Directors

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
08/07/2014	09/30/2014	10/15/2014	0.1500	0.3125	0.359375

INFORMATION FOR INVESTORS

Stock Exchange Listing

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

Rating Agencies

Innergex Renewable Energy Inc. is rated BBB- by S&P and BB (high) by DBRS (unsolicited).
Series A Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P and Pfd-4 (high) by DBRS (unsolicited).
Series C Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P and Pfd-4 (high) by DBRS (unsolicited).

Transfer Agent and Registrar

Computershare Investor Services Inc.
1500 University Street, 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 Trudel, MBA
Chief Investment Officer and Senior Vice President – Communications

Marie-Josée Privyk, CFA, SIPC
Director – Investor Relations

INNERGEX

Longueuil head office
1111 Saint Charles Street West
East Tower, Suite 1255
Longueuil, Quebec J4K 5G4

Telephone: 450 928-2550
Fax: 450 928-2544
Email: info@innergex.com

Vancouver office
200-666 Burrard St., Park Place
Vancouver, British Columbia V6C 2X8

Telephone: 604 633-9990
Fax: 604 633-9991

www.innergex.com