

FORWARD-LOOKING INFORMATION

To inform readers of the Company's future prospects, this document contains forwardlooking 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 states that certain events will or will not occur. It represents the projections and expectations of the Company relating to future events or results, as of the date of this document. 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, or estimated project costs, to inform readers of the potential financial impact of expected results, of the expected commissioning of development projects, of recently announced acquisitions, of its ability to sustain current dividends and dividend increases and its ability to fund its growth. Such information may not be appropriate for other purposes. ASSUMPTIONS: The Forward-Looking Information is based on certain key assumptions made by the Company, including those concerning hydrology, wind regimes and solar irradiation, performance of operating facilities, financial market conditions, and the Company's success in developing new facilities. RISKS AND UNCER-TAINTIES: Forward-Looking Information involves risks and uncertainties that may cause the 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 Company's Annual Information Form in the "Risk Factors" section and include, without limitation: the ability of the Company to execute its strategy; its ability to access sufficient capital resources; liquidity risks related to derivative financial instruments; changes in hydrology, wind regime and solar irradiation; delays and cost overruns in the design and construction of projects; health, safety and environmental risks; the ability to develop new facilities; obtainment of permits; variability of installation performance and related penalties; equipment failure; interest rate fluctuations and refinancing risk; financial leverage and restrictive covenants governing current and future indebtedness; declaration of dividends at the discretion of the board; the ability to secure new power purchase agreements; the ability to retain senior management and key employees; litigation; performance of major counterparties; relationships with stakeholders; equipment supply; regulatory and political changes; the ability to secure appropriate land; reliance on power purchase agreements; reliance on shared transmission and interconnection infrastructure; water and land rental expense; assessment of water, wind and sun resources and associated electricity production; dam safety; natural disasters and force majeure; foreign exchange fluctuations; sufficiency of insurance coverage; a credit rating that may not reflect the actual performance of the Company; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired; failure to realize the anticipated benefits of acquisitions; the inability to execute a definitive agreement and close the acquisition of the Hydroméga hydroelectric facilities and development project; the introduction of solar photovoltaic power facility operation; and fluctuations in the revenues from the Miller Creek facility based on the Mid-C spot price for electricity. Although the Company believes that the expectations and assumptions on which Forward-Looking Information is based are reasonable under 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. The Forward-Looking Information contained herein is made as at February 25, 2014, and the Company 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. The principal assumptions, risks and uncertainties concerning specific Forward-Looking Information contained in this document are more fully outlined on page 38 of this document.

NON-IFRS MEASURES DISCLAIMER

Some measures referred to in this document are not recognized measures under IFRS, and therefore may not be comparable to those presented by other issuers. Innergex believes that these indicators are important, as they provide management and readers with additional information about the Company's production and cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods. Adjusted EBITDA, Adjusted EBITDA margin, Free Cash Flow and Payout Ratio are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS. References in this document to "Adjusted EBITDA" are to revenues less operating expenses, general and administrative expenses and prospective project expenses. References to "Adjusted EBITDA Margin" are to Adjusted EBITDA divided by revenues. References to "Free Cash Flow" are to 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 declared and the portion of Free Cash Flow attributed to non-controlling interests, as well as other adjustments that represent 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, realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt and cash receipts by non-wholly owned subsidiaries for the wheeling services to be provided to another subsidiary. References to "Payout Ratio" are to dividends declared on common shares divided by Free Cash Flow. Investors 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.

SHARED EFFORTS FOR

May 10, 2013

New wind project under development

Innergex's partner, the Assembly of Mi'gmaq communities of Quebec, is allocated 150 MW for a wind energy project on the Gaspé Peninsula in Quebec. In December 2013, the partners signed a letter of intent with Hydro-Québec Distribution for a 20-year power purchase agreement, subject to an order-in-council by the Quebec government. Commercial operation of this project is expected to begin in 2016.



Renewable energy for a sustainable future

From hydroelectric facilities to wind and solar farms, discover Innergex's activities.

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July 25, 2013 Hydro acquisition in Quebec

Innergex completes the acquisition of the Magpie run-of-river hydroelectric facility, which has an installed capacity of 40.6 MW and long-term average annual production of 185 GWh.



Key principles

Innergex follows key principles in order to provide a solution to the energy challenges of both today and tomorrow, to protect the environment while optimizing the use of natural resources to produce electricity, and to earn and sustain its social acceptability.

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IN REVIEW can also be read online at www.innergex.com



Viger-Denonville – The project of an entire community

In 2013, Viger-Denonville was the first community wind farm from the 2009 Request for Proposals to start commercial operation. An outstanding example of collaboration.

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Official inauguration of the Viger-Denonville wind farm
Innergex and the Rivière-du-Loup Regional County Municipality officially celebrate the community wind farm, which began commercial operation on November 19, 2013.

December 20, 2013

Included in several S&P/TSX indices

During the quarterly review of the S&P/TSX index family, Innergex is added to the S&P/TSX Composite Index, as well as the S&P/TSX Composite Dividend Index, the S&P/TSX Equity Income Index and the S&P/TSX Composite Low Volatility Index. The company was already included in the S&P/TSX SmallCap Index and the S&P/TSX Renewable Energy and Clean Technology Index.

By doing something different

The story of the Kwoiek Creek run-of-river hydro project.

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Dividends and interest rates

Jean La Couture, Chairman of the Board, addresses the company's dividend distribution and exposure to rising interest rates.

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February 2014

Commissioning of two hydro facilities in British Columbia

Innergex commissions two new hydroelectric facilities in British Columbia: the 17.5 MW Northwest Stave River facility, acquired during the Cloudworks acquisition in 2011 as a development project, and the 49.9 MW Kwoiek Creek facility, developed in partnership with the Kanaka Bar Indian Band. These facilities were completed on time and on budget in December 2013 and commissioned effective December 18, 2013 and January 1, 2014, respectively.

Active on the financing front

Innergex has remained active in the financial markets in 2013. In May, it closed \$72 million in project financing for the Northwest Stave River hydro facility; in June, it successfully refinanced the Carleton wind farm with \$53 million in projectlevel debt and extended its \$425 million revolving term credit facility to 2018; and in August, the company and its joint-venture partner secured \$62 million in project financing for the Viger-Denonville community wind farm.

December 17, 2013

Agreements with First Nation for a potential wind project

Innergex and the Saik'uz First Nation sign a Letter of Intent and a Traditional Knowledge Protocol Agreement regarding the development of a wind energy project in the Nulki Hills, near Vanderhoof, British Columbia.



Dashboard

- Financial and operational highlights
- Report card

AND MORE

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RENEWABLE ENERGY FOR A SUSTAINABLE FUTURE

NNERGEX CURRENTLY HAS A PORTFOLIO OF 25 RUN-OF-RIVER HYDROELECTRIC FACILITIES. INCLUDING 13 IN BRITISH COLUMBIA, EIGHT IN QUEBEC, THREE IN ONTARIO. AND ONE IN THE UNITED STATES, WITH A TOTAL GROSS INSTALLED CAPACITY OF 517 MW. HYDRO REMAINS **INNERGEX'S PRIMARY AND PREFERRED** SOURCE OF RENEWABLE ENERGY, REPRESENTING 70% OF THE **ELECTRICITY IT GENERATED IN 2013.** THE COMPANY REMAINS VERY ACTIVE IN THE HYDROELECTRIC SECTOR. IN 2013, IT COMPLETED THE ACQUISITION OF THE 40.6 MW MAGPIE FACILITY IN

QUEBEC AND COMPLETED
CONSTRUCTION OF THE 49.9 MW
KWOIEK CREEK AND 17.5 MW
NORTHWEST STAVE RIVER FACILITIES IN
BRITISH COLUMBIA, WHICH BEGAN
OPERATING AT THE END OF 2013. THE
ADDITION OF THESE THREE FACILITIES
HAS INCREASED INNERGEX'S GROSS
INSTALLED HYDROELECTRIC CAPACITY
BY 26%. THE COMPANY ALSO HAS FOUR
HYDROELECTRIC PROJECTS UNDER
DEVELOPMENT WITH POWER
PURCHASE AGREEMENTS IN BRITISH
COLUMBIA, ALL OF WHICH SHOULD BE
IN OPERATION BY THE END OF 2016.

Innergex Renewable Energy Inc. is a leading Canadian independent renewable power producer founded in 1990. The company develops, owns, and operates run-of-river hydroelectric facilities, wind farms, and solar photovoltaic farms and carries out operations in Quebec, Ontario and British Columbia and in Idaho, USA. In 2013, the company produced 2,382 GWh of electricity, generating revenues of \$198 million. As of February 2014, the company had 32 operating facilities with a total net installed capacity of 672 MW, and five projects under development with a total net installed capacity of 210 MW for which power purchase agreements have been secured. Innergex also has several prospective projects with an aggregate net capacity totalling more than 2,900 MW. Its shares are listed on the Toronto Stock Exchange under the symbol "INE".











NNERGEX CONTINUES
TO PURSUE ITS AMBITIOUS
DEVELOPMENT PROGRAM, WITH
FIVE PROJECTS CURRENTLY UNDER
DEVELOPMENT, INCLUDING ONE
WIND PROJECT IN QUEBEC AND
FOUR HYDROELECTRIC PROJECTS
IN BRITISH COLUMBIA.

CONSTRUCTION AT THE
TRETHEWAY CREEK, UPPER
LILLOOET RIVER AND BOULDER
CREEK HYDROELECTRIC PROJECTS
BEGAN IN THE FOURTH QUARTER
OF 2013, WHILE CONSTRUCTION

AT THE BIG SILVER CREEK PROJECT IS SCHEDULED TO BEGIN IN THE SPRING OF 2014. ALL FOUR PROJECTS ARE EXPECTED TO BE IN OPERATION BY THE END 2016.

IN QUEBEC, THE COMPANY AND ITS FIRST NATIONS PARTNER, THE MI'GMAQ COMMUNITIES OF QUEBEC, CONTINUE TO ADVANCE THE MESGI'G UGJU'S'N WIND PROJECT. IN 2013, THE ENVIRONMENTAL ASSESSMENT FOR THE PROJECT WAS COMPLETED AND SUBMITTED

TO THE MINISTRY OF SUSTAINABLE DEVELOPMENT, ENVIRONMENT, WILDLIFE AND PARKS. IN DECEMBER 2013, THE PARTNERS SIGNED A LETTER OF INTENT WITH HYDRO-QUÉBEC DISTRIBUTION FOR A 20-YEAR POWER PURCHASE AGREEMENT, SUBJECT TO AN ORDER-IN-COUNCIL BY THE QUEBEC GOVERNMENT. PROJECT CONSTRUCTION IS EXPECTED TO BEGIN IN 2015 AND COMMERCIAL OPERATION IS EXPECTED TO START IN 2016.





Michel Letellier has been President and Chief Executive Officer of Innergex since 2007. He joined Innergex in 1997 and has been active in the renewable energy sector since 1990.

INTERVIEW

WE ARE PART OF THE SOLUTION

Michel Letellier, President and Chief Executive Officer, positions Innergex as part of the solution to climate change.

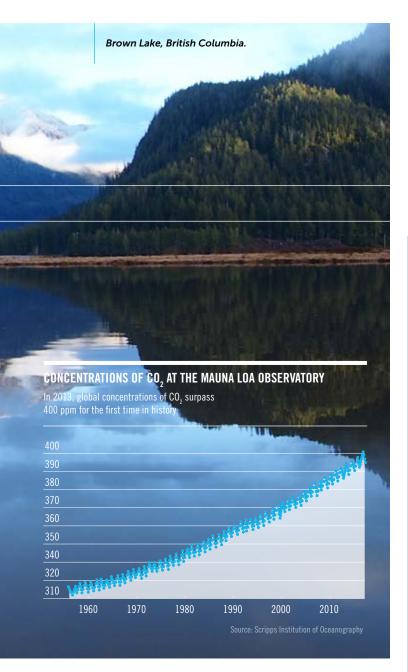
e've been hearing a lot about electricity surpluses lately. What is your position?

Much has been written in the newspapers about electricity surpluses, which appear to be a key challenge across Canada right now. Cyclical imbalances between supply and demand are common for any industry, and particularly so for the electricity sector, where supply and demand are notably desynchronized. Innergex has been active in this sector for more than 20 years; we have seen many such cycles, and will see many more in the years to come. The real question is what happens once those surpluses are gone.

o what is the real challenge we should focus on?

The real challenge is for people to have access to energy that is reliable, affordable, clean and renewable.

Planning for energy procurement is a political responsibility. And it is precisely in periods of electricity surpluses that governments must plan their energy requirements, not only because new capacity takes time to build, but also because that's when they can afford to make important policy decisions and commitments that will have a lasting impact.



Innergex's vision is to provide sustainable energy for a greener future.

s this where you come in?

Renewable energy is part of the solution to climate change. Our energy produces no greenhouse gas emissions and its sources are inexhaustible.

ut isn't a shift to renewable energy going to cost more?

The cost of renewable energy is already competitive. For example, we can build a run-of-river hydro facility with a contract price of approximately \$0.08 per kWh in Quebec, and approximately \$0.10 per kWh in British Columbia, which is comparable to what it costs the public utilities. New wind energy can be supplied for approximately \$0.09 per kWh in these markets.

Furthermore, unlike fossil energy, renewable energy costs can have an added benefit in that they are generally fixed for long periods of time – typically 20 to 40 years – through the use of long-term power purchase agreements. This provides public utilities, and ultimately consumers, with many years of protection against sudden or sharp increases in the price of electricity.

Globally, we have only just begun to harness the potential of renewable energy. Its cost should continue to decline as growing demand helps to reduce production costs through economies of scale and technological improvements. More importantly, its cost will become downright attractive when environmental and social externalities, such as the cost of pollution, are internalized.

Moreover, anyone concerned about costs should think about the cost of doing nothing to address climate change.

o you are confident about the future of Innergex?

As a renewable energy producer, Innergex is part of the solution to climate change. We continuously invest human and financial capital in our portfolio of prospective projects because they are the future.

hat kind of commitments should governments be making with respect to energy?

I'm not a climatologist, but witnessing the polar ice cap melt more and faster than ever tells me that the planet's getting warmer. In 2013, carbon dioxide particles in the atmosphere reached a new record, exceeding 400 parts per million. Experts indicate that if these increase beyond 450 parts per million, the effects of climate change will become irreversible and dangerous. We are no longer making scientific suppositions. Climate change is real. Individuals, corporations, and governments have a duty to address this problem. Society must commit to replacing fossil energy, and governments' role is to enact policies to this end.



We are affected by the impact of greenhouse gases on the planet, and we are proud to create infrastructure that produces practically none. The unbridled consumption of fossil energy on a global scale reveals a lack of awareness that will only subside when the costs of the pollution it generates are reflected in its price. When that happens, renewable energy will emerge as a choice that is both competitive and responsible. For Innergex employees, it is an advantage to work for a producer of green energy.

Renaud de Batz, Senior Vice President
 Hydroelectric Development



It is encouraging to see that people and governments are becoming increasingly aware of the effects of climate change and that they are choosing to do something about it. We are deeply convinced of the merits of our work, and capital market participants are beginning to recognize the purpose and value of investing in renewable energy assets. Hopefully, in time, the general public will also come to realize that when we take into account the cost of pollution and the subsidies on fossil fuels, renewable energy is a very cost-effective solution to climate change.

 Jean Trudel, Chief Investment Officer and Senior Vice President – Communications



We are aware that our projects have an impact on the environment, especially during their construction, which can last two or three years. Our team of engineering experts ensures that structures are built with care in ways that minimize their environmental and social impact while maximizing their performance and durability – from 50 to 100 years for our hydroelectric plants. After all, it doesn't actually cost more to do things properly from the start.

Claude Chartrand,
 Vice President – Engineering



Our past experience with local communities and First Nations speaks for itself – in fact, it recently earned us the distinction of being selected by the Mi'gmaq of Quebec to jointly develop a wind energy project, beyond the technical or economic aspects of our proposal. Our local partners are key to the success of any project, and consequently to the sustainable success of Innergex. Our employees are motivated and enthused to work for a company that values this approach and is appreciated by its partners and by the community.

Peter Grover, Senior Vice President
 Project Management



We all need electricity. Given the reality of climate change, we need to generate electricity with the lowest greenhouse gas emissions possible. Culturally, Innergex has always sought to minimize its impact on the environment. We routinely conduct multi-year environmental monitoring programs for newly operating projects. Through scientific study and analysis, our goal is to understand the effects of each of our projects and continuously validate the hydroelectric technology we employ in British Columbia. Results so far indicate not only that our projects generate very low emissions, but that they also have few negative effects on the environment.

Matt Kennedy, Vice President
 Environment, Western Region



No other renewable source of energy can match hydroelectricity in terms of sustainability. Run-of-river hydro is particularly appealing because it represents development on a human scale. We are involved in every facet of a project's development and we witness first hand all the good it produces: reliable and renewable power, shared economic benefits, community pride, and a minimal impact on the environment. We are fortunate to have an abundance of rivers with hydroelectric potential in Canada, and we should make their development a priority, in a way that makes sense economically, socially and environmentally.

François Hébert, Senior Vice PresidentOperations and Maintenance



We cannot face climate change alone. But what we do at Innergex contributes to solving this problem. Although many companies produce renewable energy, Innergex is one of the few pure plays in the sector. This leads us to forgo development opportunities that could certainly accelerate our growth prospects, but would infringe on our key principles. Furthermore, choosing to focus on this very narrow sector has led us to combine our social conscience towards the environment with a social conscience towards local communities and to promote a collaborative approach that is solidly anchored in our current practices.

 Jean Perron, Chief Financial Officer and Senior Vice President



The experience we have acquired through our many projects has developed our deep understanding of the environmental and social challenges within our sector. The approach we favour, inspired by these principles, answers a real need and leads us to develop best practices that often become standards, and then regulations. In this respect, we truly do effect change.

Richard Blanchet, Senior Vice President
 Western Region



Behind these principles are the people of Innergex. The growing awareness about the environment attracts people who have become conscious of the impact of climate change, who are concerned about the environment and who want to be part of the solution, not only through their choice of industry to work in, but also in the way they choose to work. Each of them brings complementary skills and, together, we form a team whose accomplishments in terms of social acceptability, development and respect for the environment make it a pioneer in renewable energy.

 Anne Cliche, Vice President – Organizational Development and Talent Management Viger-Denonville community wind farm in Quebec.

In 2013, Innergex produced 2,382 GWh of electricity generating virtually no CO_2 emissions. If it had been produced using coal, this amount of electricity would have generated 2.3 million tonnes of CO_2 emissions. If it had been produced using natural gas, this amount of electricity would have generated 1.3 million tonnes of CO_2 emissions.

INNERGEX'S KEY PRINCIPLES

We believe that people should have access to reliable, affordable, clean and renewable energy. Climate change is real. We believe that renewable energy is part of the solution to climate change. We believe in a level playing field in electricity procurement. We support carbon pricing or any other means of internalizing environmental and social costs in the price of electricity. We believe in the protection of our environment and in the responsible development of natural resources. We support a comprehensive and efficient regulatory and planning framework.

We believe that social acceptance is the cornerstone of successful project development and that strong projects are built on long-term cooperation with stakeholders and by working in collaboration with First Nations and local communities.

We believe in long-term sustainable development that balances social, environmental, and economic imperatives.

We believe in lasting relations with our employees, our partners, and our external stakeholders built on respect, transparency, and integrity.

We believe that Innergex can effect change.

Innergex follows these Key Principles in order to provide a solution to the energy challenges of both today and tomorrow, to protect the environment while optimizing the use of natural resources to produce electricity, and to earn and sustain its social acceptability.

Innergex engages with its partners and stakeholders, governed by core values of integrity, responsibility, transparency, and collaboration, in a perspective of longevity and resource-sharing.

DIVERSIFICATION IS KEYTO PORTFOLIO BALANCE

iversification has been proven to reduce risks and improve operating performance stability. Innergex diversifies its portfolio of assets in two ways: by energy source and by geography. As a result, the company protects itself from possible adverse conditions affecting water, wind, or sun resources. Diversification also provides the company with the flexibility to react to favourable political and economic circumstances arising in one market, while waiting for these conditions to improve in another.

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VANCOUVER



Innergex expanded into the British Columbia market in 2002 with the construction of the Rutherford Creek facility. Today, the company operates 13 run-of-river hydroelectric facilities in this province. It also has three hydroelectric projects under construction and one under development, and a 1,325 MW portfolio of prospective hydroelectric and wind projects in this region. Innergex also owns a 9.5 MW run-of-river hydroelectric facility in Idaho, USA.





prospective hydro, wind, and solar projects in the eastern region.



SITES IN OPERATION



ASHLU CREEK (BC) DATE OF COMMISSIONING 2009

INSTALLED CAPACITY (gross MW) 49.9 OWNERSHIP (%) 100.00 PPA FXPIRY 2039



DOUGLAS CREEK (BC)

DATE OF COMMISSIONING 2009 INSTALLED CAPACITY (gross MW) 27.0 OWNERSHIP (%) 50.01 PPA EXPIRY 2049



KWOIEK CREEK (BC)

DATE OF COMMISSIONING 2014 INSTALLED CAPACITY (gross MW) 49.9 OWNERSHIP (%) 50.00 PPA FXPIRY 2054



MONTMAGNY (QC)

DATE OF COMMISSIONING 1996 INSTALLED CAPACITY (gross MW) 2.1 OWNERSHIP (%) 100.00 PPA EXPIRY 2021*



SAINT-PAULIN (QC)

DATE OF COMMISSIONING 1994 INSTALLED CAPACITY (gross MW) 8.0 OWNERSHIP (%) 100.00 PPA EXPIRY 2014



VIGER-DENONVILLE (QC) DATE OF COMMISSIONING 2013

INSTALLED CAPACITY (gross MW) 24.6 OWNERSHIP (%) 50.00 PPA EXPIRY 2033



BAIE-DES-SABLES (QC)

DATE OF COMMISSIONING 2006 INSTALLED CAPACITY (gross MW) 109.5 OWNERSHIP (%) 38.00 PPA EXPIRY 2026



FIRE CREEK (BC)

DATE OF COMMISSIONING 2009 INSTALLED CAPACITY (gross MW) 23.0 OWNERSHIP (%) 50.01 PPA EXPIRY 2049



L'ANSE-À-VALLEAU (QC)

DATE OF COMMISSIONING 2007 INSTALLED CAPACITY (gross MW) 100.5 OWNERSHIP (%) 38.00 PPA EXPIRY 2027



NORTHWEST STAVE RIVER (BC) DATE OF COMMISSIONING 2013

INSTALLED CAPACITY (gross MW) 17.5 OWNERSHIP (%) 100.00 PPA EXPIRY 2053



STARDALE (ON)

DATE OF COMMISSIONING 2012 INSTALLED CAPACITY (gross MW) 33.2 DC OWNERSHIP (%) 100.00 PPA EXPIRY 2032



DATE OF COMMISSIONING 2009 INSTALLED CAPACITY (gross MW) 22.0 OWNERSHIP (%) 50.01



BATAWA (ON)

DATE OF COMMISSIONING 1999 INSTALLED CAPACITY (gross MW) 5.0 OWNERSHIP (%) 100.00 PPA EXPIRY 2029



FITZSIMMONS CREEK (BC)

DATE OF COMMISSIONING 2010 INSTALLED CAPACITY (gross MW) 7.5 OWNERSHIP (%) 66.67 PPA EXPIRY 2050



LAMONT CREEK (BC)

DATE OF COMMISSIONING 2009 INSTALLED CAPACITY (gross MW) 27.0 OWNERSHIP (%) 50.01 PPA EXPIRY 2049



PORTNEUF 1 (QC)

DATE OF COMMISSIONING 1996 INSTALLED CAPACITY (gross MW) 8.0 OWNERSHIP (%) 100.00 PPA EXPIRY **2021***



STOKKE CREEK (BC)

PPA EXPIRY 2049



BROWN LAKE (BC)

DATE OF COMMISSIONING 1996 INSTALLED CAPACITY (gross MW) 7.2 OWNERSHIP (%) 100.00 PPA FXPIRY 2016



GLEN MILLER (ON)

DATE OF COMMISSIONING 2005 INSTALLED CAPACITY (gross MW) 8.0 OWNERSHIP (%) 100.00 PPA EXPIRY 2025



MAGPIE (QC)

DATE OF COMMISSIONING 2007 INSTALLED CAPACITY (gross MW) 40.6 OWNERSHIP (%) 100.00 PPA FXPIRY 2032



PORTNEUF 2 (QC)

DATE OF COMMISSIONING 1996 INSTALLED CAPACITY (gross MW) 9.9 OWNERSHIP (%) 100.00 PPA EXPIRY 2021*



TIPELLA CREEK (BC)

DATE OF COMMISSIONING 2009 INSTALLED CAPACITY (gross MW) 18.0 OWNERSHIP (%) 50.01 PPA EXPIRY 2049



CARLETON (QC)

DATE OF COMMISSIONING 2008 INSTALLED CAPACITY (gross MW) 109.5 OWNERSHIP (%) 38.00 PPA FXPIRY 2028



GROS-MORNE (I & II) (QC)

DATE OF COMMISSIONING 2011 INSTALLED CAPACITY (gross MW) 211.5 OWNERSHIP (%) 38.00 PPA EXPIRY 2032



MILLER CREEK (BC)

DATE OF COMMISSIONING 2003 INSTALLED CAPACITY (gross MW) 33.0 OWNERSHIP (%) 100.00 PPA EXPIRY 2033



PORTNEUF 3 (QC)

DATE OF COMMISSIONING 1996 INSTALLED CAPACITY (gross MW) 8.0 OWNERSHIP (%) 100.00 PPA EXPIRY 2021*



UMBATA FALLS (ON)

DATE OF COMMISSIONING 2008 INSTALLED CAPACITY (gross MW) 23.0 OWNERSHIP (%) 49.00 PPA EXPIRY 2028



CHAUDIÈRE (QC)

DATE OF COMMISSIONING 1999 INSTALLED CAPACITY (gross MW) 24.0 OWNERSHIP (%) 100.00 PPA FXPIRY 2019*



HORSESHOE BEND (USA)

DATE OF COMMISSIONING 1995 INSTALLED CAPACITY (gross MW) 9.5 OWNERSHIP (%) 100.00 PPA EXPIRY 2030



MONTAGNE SÈCHE (QC)

DATE OF COMMISSIONING 2011 INSTALLED CAPACITY (gross MW) 58.5 OWNERSHIP (%) 38.00 PPA EXPIRY 2031



RUTHERFORD CREEK (BC) DATE OF COMMISSIONING 2004

INSTALLED CAPACITY (gross MW) 49.9 OWNERSHIP (%) 100.00 PPA EXPIRY 2024



UPPER STAVE RIVER (BC)

DATE OF COMMISSIONING 2009 INSTALLED CAPACITY (gross MW) 33.0 OWNERSHIP (%) 50.01 PPA EXPIRY 2049

WINDSOR (QC)

DATE OF COMMISSIONING 1996 INSTALLED CAPACITY (gross MW) 5.5 OWNERSHIP (%) 100.00 **PPA EXPIRY 2016***

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.

TOWARDS A GREENER FUTURE

As one of the largest independent renewable power producers in Canada, Innergex assumes a leadership role in advocating for the development of a strong and sustainable renewable energy industry in Canada.

The company continues to pursue the development of its portfolio of prospective hydro, wind, and solar projects, and remains ready to respond to future requests for proposals.

In Ontario, the government announced in June 2013 that it would no longer procure large renewable energy capacity under the Feed-In Tariff Program (FIT) for large projects and, as a result, the Ontario Power Authority discontinued the previously submitted Large FIT project applications for which no contract had been awarded. Instead, Ontario will seek to institute a competitive procurement process which will take into account local needs and considerations, including those of municipalities and First Nations. In Ontario's Long-Term Energy Plan, released in December 2013, the government reiterated its commitment to investing in renewable energy and declared its intention to launch this new procurement process in the spring of 2014. Planned capacity procurement would target 300 MW of wind energy and 140 MW of solar energy in 2015 and another 300 MW of wind energy and 150 MW of solar energy in 2016, with planned annual revisions. Innergex has a number of wind and solar projects that it continues to advance in preparation for submissions under a future competitive bid process. Several prospective projects in Ontario, especially in the wind sector, remain predicated on transmission grid expansion in the northern part of the province and represent more long-term growth potential.

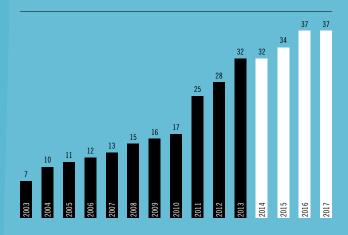
In British Columbia, BC Hydro released its *Integrated Resource Plan* in November 2013, which calls for "a set of actions that will support a healthy, diverse clean energy sector and promote clean energy opportunities for First Nations," but provides no specific procurement targets

for renewable energy at this time. The province's significant plans to develop its mining and liquefied natural gas (LNG) sectors may provide development opportunities for the renewable energy sector in light of the Premier's pledge to produce the "cleanest LNG in the world" and the importance for the population of minimizing greenhouse gas emissions. Innergex hopes to capitalize on its strong industry presence, its positive track record with local communities and First Nations, and its expertise in both hydroelectric and wind energy as it continues to advance the development of a number of prospective projects in this province.

In Quebec, Hydro-Québec launched a request for proposals in December 2013 for the procurement of 450 MW of new wind energy, including 300 MW for projects in the Lower St. Lawrence and Gaspésie regions and 150 MW for projects anywhere in the province. Regulations stipulate a maximum price of \$0.09 per kWh, minimum local content requirements of 60%, and ownership of 50% or more of each project by a local entity, including municipalities and First Nations. Innergex has several wind projects that it intends to submit under this request for proposals before the September 2014 deadline.

NUMBER OF SITES IN OPERATION

at December 31 (actual 2003-2013, projected 2014-2017)



VIGER-DENONVILLE THE PROJECT OF AN ENTIRE COMMUNITY

In 2013, Viger-Denonville was the first community wind farm from the 2009 Request for Proposals to start commercial operation. An outstanding example of collaboration.

ovember 19, 2013 marked the start of commercial operation for the Viger-Denonville community wind farm, co-owned by Innergex and the Rivière-du-Loup Regional County Municipality (RCM). This achievement was celebrated a few days later with an official inauguration ceremony, where the atmosphere was one of shared pride, belonging and friendship. The ceremony reflected the bonds that have formed between the people of Innergex and the people of this community. Mutual respect, attentiveness, transparency and honesty have typified the day-to-day contacts between company representatives and community members - to the point that the gathering for the inauguration felt more like a family reunion than an official ceremony.

For this project, Innergex was particularly aware that relations with the host communities had to get off on the

right foot. A previous attempt to develop a wind project with another promoter had failed, leaving the local people full of misgivings. So right from day one, when the people of the RCM and Innergex first made contact in 2006, efforts were made to build genuine collaboration between the two partners. This collaboration can be seen in the fact that local landowners agreed to host the twelve wind turbines of this project sited entirely on private land. It can also be seen in the fact that 26 local businesses from across the RCM were involved in the construction work, a testament to the partners' drive to maximize the project's local benefits. And it can be seen once more in the fact that Jean-Sébastien Roy, a young local resident and an electrician by trade, has been hired as the wind farm's operator. According to Philippe Dionne, mayor of Saint-Paul-de-la-Croix, "people are happy because they were consulted every step of the way during the realization of this project."

IT'S ALL IN THE DETAILS

Innergex bought the old presbytery in Saint-Paul-de-la-Croix from a local resident, with the intention of converting it into the project operations office. Not long afterwards, however, the building suffered considerable water damage and major renovations were in order. Much of the building's interior had to be ripped out, decontaminated and renovated, and the heating system needed to be replaced. At first, Innergex considered modernizing the interior. However, the company soon realized how important it was to people like Philippe Dionne, Michel Lagacé (warden of the Rivière-du-Loup RCM) and Mélanie Milot (the RCM's heritage officer) that the heritage quality of this building be preserved, even though it wasn't officially classified as a heritage building. So the partners worked hard to preserve its historic cachet during the renovations.



On November 29, 2013, the official inauguration ceremony for the Viger-Denonville wind farm took place in an atmosphere of shared pride, belonging and friendship. More than 130 people gathered, including elected officials from the two host municipalities and the RCM's 12 member municipalities,

provincial government delegates, landowners, representatives of the follow-up committee, the local businesses involved in project construction, Hydro-Québec, the turbine manufacturer REpower, the contractor Boréa, professional associations and environmental organizations.

"If there's one word to describe this day, it's pride! Pride in being a resident of this RCM within Quebec!"

- Michel Lagacé, President of the regional conference of elected officers of the Lower St. Lawrence and Warden of the Rivière-du-Loup RCM





"HOW, THEN, DOES OUR COMMUNITY MOVE FORWARD WHEN OUR PAST IS SO HEAVY ON OUR HEARTS AND ON OUR MINDS?

BY DOING SOMETHING DIFFERENT."

nspired by his vision of a better future and a strong desire to do something different, in the late 1980s, Chief James Frank led the Kanaka Bar Indian Band in applying for a water license when he noticed the permit rush for water licenses to develop run-of-river hydro projects following the announcement of BC Hydro's independent power production policy. For Chief Frank, "the power of Kwoiek Creek has always been known to Kanaka. The clean

energy industry represents an opportunity to exercise Nlaka'pamux rights and title in a modern way."

The band started gathering baseline data on land use and water flows. It engaged with the federal and provincial governments through the project review and permitting process. It tried – unsuccessfully – to partner with three different companies to develop this project. At last, in 2005, it entered into a 50/50 joint venture with Innergex that would provide the expertise and capital required to



"A successful project requires a relationship based on trust. It is hard to establish and easy to lose, and it needs continual effort, by everyone, throughout the project's lifetime."

Patrick Michell, Kanaka Ba
 Community Liaison

"[IPPs are] a prime industry for First Nations across the province — who are largely remote, who are largely away from the urban centres and are looking for ways to employ people and to generate revenue that's going to help provide support for their communities"

Adam Olsen, native leader and Interim
 Leader of the BC Green Party



Penstock installation at the Kwoiek Creek hydroelectric project in British Columbia.

realize the project while ensuring band participation in all design, planning and construction decisions.

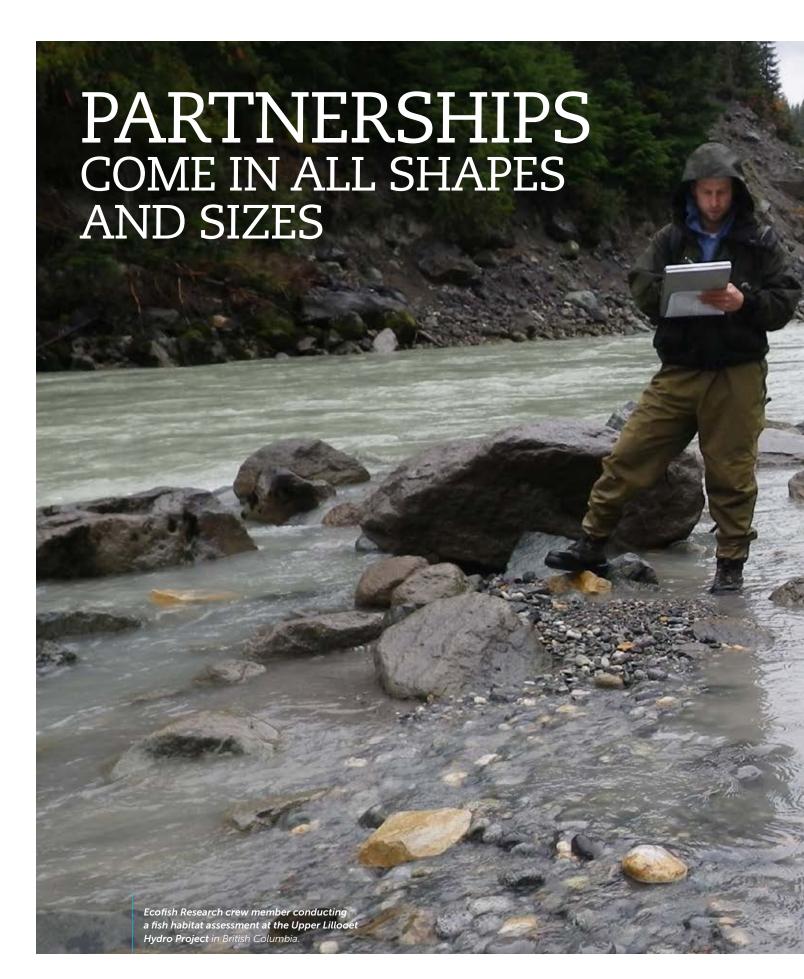
The two partners submitted the project under BC Hydro's 2006 Call for Tenders for clean energy and obtained a 40-year power purchase agreement, giving the green light for the project to move forward. It took three years to complete the environmental assessment certification process and another two years to consult with more than 16 neighbouring First Nations communities,

many of whom would have to agree to let the project's transmission line cross their territory. Construction finally began in the spring of 2011. Local job creation was a priority for the community, and during construction more than 40% of workers at the site were Kanaka Bar members, twice the average for similar construction projects in the province. A cable crane was built as a shortcut over the Fraser River to accelerate the transportation of materials and equipment. A seven-kilometer penstock to carry the water from the intake to the powerhouse was installed underground. Degraded access roads and forestry bridges were repaired and will be maintained to industry standards hereafter. And a kilometer-long fish habitat compensation channel was created, featuring several diversions, ponds and small lakes.

In November 2013, more than 20 years after Chief Frank's idea first took shape, the plant began producing its first megawatts of electricity.

The Kanaka Bar members are very proud of their accomplishment. "Our communities' participation in the clean energy sector has provided Kanaka Bar, all our local area residents and all of British Columbia with generational assets and long-term benefits," says Patrick Michell, Kanaka Bar Community Liaison. "For a small community like Kanaka Bar, the idea of creating 'showcases' and setting standards was certainly not on our minds back in 1990. Today, though, if we are in a position to demonstrate what collaboration can accomplish, that's what Kanaka will do." he adds.

In fact, the success of Kwoiek Creek has encouraged the band to identify several other renewable energy projects it intends to develop in the future. "But for now," Patrick Michell says, "the economic trickle-down effect plus all the smiles on people's faces and the improvement in community pride, self-worth and self-confidence is all that matters."







A partner of choice for First Nations

Innergex has gained a reputation as a partner of choice for First Nations seeking to develop business opportunities in the renewable energy sector. The company enjoys active relationships with more than 40 First Nations in British Columbia, Ontario and Quebec, and has signed formal revenue-sharing agreements with more than 20 of them. "We value our partnerships and will continue to build on these relationships wherever and whenever conditions allow for the development of new renewable energy projects," says Bas Brusche, Innergex's Director — Public Affairs, Western Region.

- The Lil'wat Nation, with whom Innergex has signed several Impact Benefit Agreements since 2002 for the Upper Lillooet River and Boulder Creek projects currently under construction, also plans to jointly develop other renewable energy projects with Innergex in their traditional territory.
- In 2002, Innergex signed an agreement with the Ojibways of the Pic River First Nation, who were already part-owners

of two run-of-river hydroelectric facilities, to assess the potential for additional hydroelectric development within their traditional territory; this led to a joint venture to develop the 23 MW Umbata Falls project, which began commercial operation in 2008.

- In 2005, the Kanaka Bar Indian Band and Innergex formed a partnership to develop a 49.9 MW run-of-river hydroelectric project for which the First Nations community owned the water license; that project, known today as the Kwoiek Creek facility, began operating in December 2013.
- In 2012, Innergex was chosen by the Mi'gmaq communities of Quebec as their partner for the development of a 150 MW wind project on the Gaspé Peninsula in Quebec. In December 2013, the partners signed a letter of intent with Hydro-Québec Distribution for a 20-year power purchase agreement, which is subject to an order-in-council by the Quebec government, and are proceeding with the project's development.

- The Stellat'en First Nation near Fraser,
 British Columbia, approached Innergex to
 develop a wind farm for which it owns
 development rights and has already begun
 wind measurements.
- In 2013, Innergex signed a letter of intent and a protocol agreement with the Saik'uz First Nation for the development of a wind farm near Vanderhoof, British Columbia.
- Also in 2013, the Sts'ailes First Nation, with whom Innergex (formerly Cloudworks) has signed Participation Agreements since 2010 for existing facilities and projects currently under construction or development such as Tretheway Creek and Big Silver Creek, signed an Economic Development Agreement with Innergex to jointly develop the hydroelectric potential of their traditional territory, located mainly along Harrison Lake.



Fish habitat compensation implementation at the Kwoiek Creek hydroelectric project in British Columbia.



Test-pilot for BC's environmental mitigation policy

Innergex participated in the BC Ministry of Environment consultations on its proposed Policy for Mitigating Impacts on Environmental Values, and when it came time to test the policy's implementation on some actual projects, the company volunteered to do so at its Tretheway Creek hydro project. The trial applications aimed to bring consistency to identifying environmental values and components, developing impact assessments, using the mitigation hierarchy and selecting mitigation measures. Over the last two years, the company has used the policy as a framework for deciding on appropriate mitigation measures for the Tretheway Creek project. In particular, it addressed the possible impact of the transmission line trajectory on potential spotted owl habitat by designating a specific area for the eventual reintroduction of this species by the province and by contributing financially to this effort.

SWITCH, alliance for a greener economy in Quebec

In 2013, Innergex became a partner and member of the advisory committee of SWITCH, an "alliance" among industry associations, non-governmental organizations, and investment funds to advocate for strong political, economic and social leadership, coherent government policies, and private-public collaboration in fostering the transition to a greener Quebec economy. The company's participation stems from its desire to act on its vision of a greener future.

The Energy Forum

In 2013, Innergex became a founding member of The Energy Forum, a collaboration among British Columbia independent power producers, industry associations, and non-governmental organizations working to address energy, climate and ecosystem challenges. The goal of this organization is to foster dialogue to address such issues as climate change, environmental stewardship, responsible development and energy efficiency.

Ecofish Research crew members conducting a mountain whitefish survey as part of the Environmental Assessment for the Upper Lillooet Hydro Project in British Columbia.

Linda Nowlan of WWF-Canada and Matt Kennedy, Innergex's VP - Environment, Western Region, at the Ashlu Creek hydroelectric facility in British Columbia.



Credit: Craig Orr.

World Wildlife Fund Canada

Over the last few years, Innergex has collaborated with World Wildlife Fund Canada as part of the BC government's consultative process on water issues. Representatives from both organizations participated in the technical advisory group on the proposed Water Sustainability Act, in support of such issues as regulating ground water and incorporating environmental water flows in all water licensing decisions.

"Innergex's collaboration, as co-chair of the Energy Forum's water 'squadron', on the BC Water Sustainability Act has increased our understanding of the operational and field challenges of implementing a new water law in BC and is helping to reach our goal of improving legal protection for environmental flows in this province."

 Linda Nowlan, WWF-Canada's Interim Regional Director, British Columbia and Pacific



Pacific Salmon Foundation – Independent review of run-of-river hydro projects in British Columbia

In October 2012, Clean Energy BC (CEBC) approached the Pacific Salmon Foundation to commission an independent scientific review of run-of-river hydroelectric projects, with a specific focus on their potential impact on salmonids, including various species of salmon and trout. As a leading independent power producer in British Columbia, Innergex actively participated in this study, sharing extensive monitoring information from most of its 13 run-of-river hydro facilities in British Columbia, volunteering time, and providing financial support indirectly through CEBC. Matt Kennedy, Innergex's Vice President - Environment, Western Region and a Registered Professional Biologist, represented the industry on the advisory council composed of environmental non-governmental organizations, provincial

and federal government representatives, academics, and run-of-river hydro developers. The results of this independent review point to limited evidence of any significant impact on salmonids from run-of-river hydroelectric facilities, and provide a strong basis for continued evaluation, collaboration and accountability on the part of independent power producers in British Columbia, in partnership with the BC government.

"It is important to point out that this is the first study of its kind in British Columbia and one of very few done anywhere. Taking a scientific approach to assessing the impact on salmonids is one that other jurisdictions should be able to learn from and, hopefully, emulate."

– Dr. Brian Riddell, President and CEO of the Pacific Salmon Foundation





Regional forum on water in Chaudière-Appalaches, Quebec.

The Chaudière-Appalaches Regional Environmental Council: supporting the implementation of sustainable development in the region

As a financial sponsor and board member of the Chaudière-Appalaches Regional Environmental Council, Innergex is supporting this organization's efforts to implement sustainable development within the region. As owner and operator of two run-of-river hydroelectric facilities in the area (Chaudière and Montmagny), Innergex is actively involved in stakeholder consultations that include elected officials and forest management experts, as well as representatives from Quebec's farmers' union and local school boards.

The regional environmental councils are active players in environmental protection and the promotion of sustainable development across Quebec. Collectively, they are recognized as the government's main counterpart on environmental issues and intervene in most major cases: wetlands and protected areas, agriculture, biodiversity, climate change, sustainable development, the protection of water and lakes, energy, forestry, residual waste, mines, transportation, and land use planning.

"Recognized for its expertise in renewable energy development, Innergex has, over the years, demonstrated its ability to integrate communities' expectations and maximize local economic benefits, while also demonstrating a constant concern for the quality of the environment."

 Guy Lessard, President of the Chaudière-Appalaches Regional Environmental Council



or the people at Innergex, sustainability isn't just about what the company does producing electricity from renewable energy sources - but about how it does it. It's about producing electricity to meet today's needs without compromising the ability of future generations to meet their own needs. From an environmental perspective, developing sustainably means harnessing the water, wind or sun in a way that avoids, minimizes, mitigates or compensates for any impact on the surrounding ecosystem... and possibly leaves the planet better off in the end. Ultimately, it's about acting responsibly.

For more than 20 years, Innergex has earned a reputation for upholding the highest environmental standards. It has continuously striven to improve its assessment, monitoring, commitment-tracking, compliance and reporting practices, and in so doing has developed innovative best practices that eventually make their way into new regulations. It has made environmental sustainability

the backbone of its development strategy, in the same way as it has made social acceptability the cornerstone.

In an industry that has some of the most stringent environmental regulations, it is difficult to go beyond the call of duty. Innergex remains keenly aware that its reputation depends in part on having well-designed and welloperated facilities, so compliance is a key focus of its environmental practices. However, the company sets itself apart by integrating environmental considerations into the earliest stages of the development process. Engineering and environmental objectives are simultaneously integrated into the design of new projects in order to protect environmental values such as wildlife and wildlife habitat, fish and fish habitat, erosion protection, vegetation, as well as heritage (including archaeological and traditional use), health and social-value components. So when the project development team estimates the permitting and construction schedules, models long-term average electricity production levels, or calculates a budget, environmental factors

are always part of the process. In turn, this has enabled the company to strike a balance between engineering functionality, economic returns, social acceptability and environmental considerations, from project design onwards.

Innergex's achievements on the environmental front are the work of a team of dedicated environmental experts consisting of biologists, environmental engineers and specialists in key areas such as habitat reconstruction and environmental permitting and monitoring: people who care about doing things right. "These people decide to work at Innergex because they genuinely care for the environment, and they firmly believe that renewable energy is the best way forward for our planet. Honouring the environment is integral to us, and we are fortunate to have a knowledgeable and committed team through which Innergex maintains the highest environmental standards year after year", says Matt Kennedy, Vice-President - Environment, Western Region.



Innergex contributes to studies on British Columbia's iconic grizzly bears

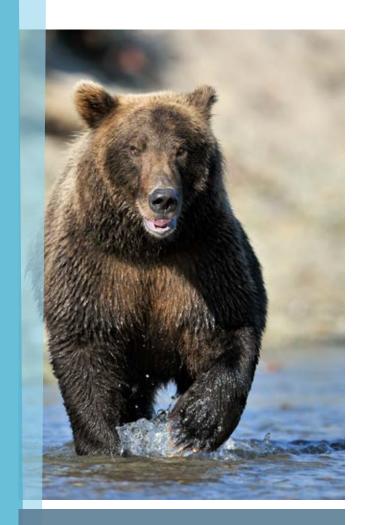
Grizzly bears evoke images of powerful, resilient animals In reality, they are a species in need of protection.

In September 2013, Innergex and its partner contributed \$300,000 to the BC Ministry of Forests, Lands and Natural Resource Operations to carry out a five-year study of the grizzly population in the Upper Lillooet drainage, where the company's Upper Lillooet Hydro Project is under construction. As part of this project's Environmental Assessment Certificate requirements, Innergex signed an agreement to contribute to the provincially led regional grizzly bear program, which is developing and implementing a grizzly bear inventory and a monitoring and evaluation program to understand what impact pending development will have on the grizzly bear population. Innergex's contribution will go towards collaring and monitoring four female grizzly bears and collecting hair-snag DNA samples

Innergex's support for BC's grizzly bears extends beyond its financial contribution. Effectively managing human activities in an effort to preserve as much grizzly habitat as possible is essential to protecting the species. During the construction phase of the Upper Lillooet Hydro Project, the company will implement extensive measures to minimize any potential impact on grizzly bears and their habitat, including foraging sites and salmon spawning streams. In addition, a Human-Wildlife Interaction Management Plan and a Human-Bear Conflict Management Plan will be implemented to maximize the safety of grizzlies — and humans — during construction and operation of the facilities.

The environmental team works with the contractor to ensure that the project construction schedule allows for the timing restrictions and mitigation measures associated with the various valued environmental components such as fish and wildlife migration, spawning, breeding, and rearing seasons, to avoid disturbance to key species.

The environmental permitting process for the Upper Lillooet Hydro Project (comprising the Upper Lillooet River, Boulder Creek and North Creek run-of-river hydroelectric facilities) took four years and represented approximately 7,500 pages of independent studies, consultations and reports, and thousands of hours of fieldwork.





Every once in a while, it is possible to do more than what environmental regulations prescribe, and Innergex's fish habitat compensation areas are a case in point. At the six Harrison Lake facilities in British Columbia, for example, most of the project's fish and fish habitat impact pertained to rainbow trout, a common species. However, the two fish habitat compensation areas were designed to also provide spawning and rearing habitat for ocean-going salmon, which are considered a higher-value species. Today, these areas are actively used not only by rainbow trout, but by spawning salmon returning every year to lay their eggs.

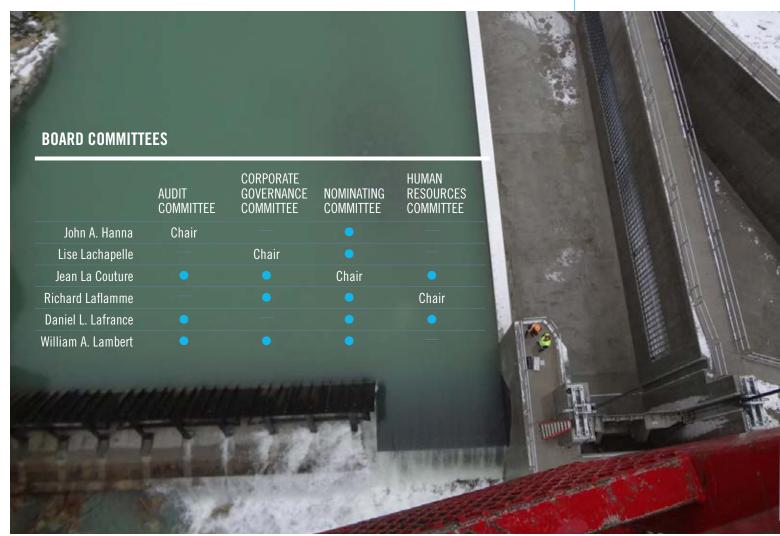


Jean La Couture is Chairman of the Board of Innergex Renewable Energy Inc.

DIVIDENDS AND INTEREST RATES

Jean La Couture, Chairman of the Board, addresses the company's dividend distribution and exposure to rising interest rates.

> Headpond filling at the Northwest Stave River hydroelectric facility in British Columbia.



INCREASED DIVIDEND

n the governance and management of Innergex's ambitious project development program and numerous acquisitions, prudence has always been the maxim of the management team and Board of Directors. Our priority remains to ensure the sustainability of the dividend by monitoring the Company's capacity to generate the expected cash flows from its ever-increasing number of facilities in operation.

In 2013, Innergex continued its impressive growth, with the commissioning of one wind farm, the completion of two hydroelectric facilities that were commissioned effective December 18, 2013 and January 1, 2014, the beginning of construction activities at three hydroelectric projects under development, the acquisition of a hydroelectric facility, and the negotiation of a power purchase agreement for a significant wind energy project. These achievements have provided management and the Board of Directors with the comfort level they need to raise the annual dividend on the Company's common shares to \$0.60 per share, representing an increase of 3.4%.

INNERGEX RENEWABLE ENERGY INC.'S BOARD OF DIRECTORS

JOHN A. HANNA*

Principal occupation: Corporate Director Innergex Director since: 2003

LISE LACHAPELLE*

Principal occupation: Corporate Director and Consultant **Innergex Director since:** 2003

JEAN LA COUTURE* - Chairman of the Board Principal occupation: President, Huis Clos Limitée Innergex Director since: 2003

RICHARD LAFLAMME*

Principal occupation: Corporate Director and pension fund administrator **Innergex Director since:** 2003

DANIEL L. LAFRANCE*

Principal occupation: Corporate Director Innergex Director since: 2003

WILLIAM A. LAMBERT

Principal occupation: Corporate Director **Innergex Director since:** 2007

MICHEL LETELLIER

Principal occupation: President and Chief Executive Officer of the company **Innergex Director since:** 2002

This decision attests to our confidence in the Company's ability to generate stable cash flows that are amply sufficient to maintain its dividend policy. Moreover, it attests to our confidence in the Company's prospects for the future.

LIMITED EXPOSURE TO THE RISE IN INTEREST RATES

Although they may appear worrisome, interest rate increases have little impact on the Company's activities, thanks to its resilient business model.

- Approximately 98% of the Company's outstanding debt is either fixed or hedged against interest rate fluctuations through the use of derivative financial instruments.
- The refinancing of operating facility debt instruments that are maturing in the coming years is protected from interest rate fluctuations by means of derivative financial instruments put in place at the time of the initial financing.
- The financing for projects that the Company is currently developing is subject to a hedging program in order to lock in the base interest rate through the use of derivative financial instruments until the Company closes the project-level financing. At the time of writing, this hedging program was essentially complete for four of the five development projects, effectively eliminating the projects' exposure to interest rate fluctuations.
- The Company's prospective projects, which do not yet have a power purchase agreement, will be priced in accordance with interest rates prevailing when they are submitted under a request for proposals or when negotiations begin.

For Innergex, shareholder value is created through the sustainability of the dividend and its potential to increase commensurately with the development or acquisition of high-quality renewable energy production facilities that generate stable cash flows.

^{*} John A. Hanna, Lise Lachapelle, Jean La Couture, Richard Laflamme and Daniel L. Lafrance were appointed directors of the Company on March 29, 2010 upon completion of the strategic combination of Innergex Power Income Fund and Innergex Renewable Energy Inc. Prior to the strategic combination, they had all been trustees since 2003 of Innergex Power Trust, a wholly owned subsidiary of Innergex Power Income Fund.

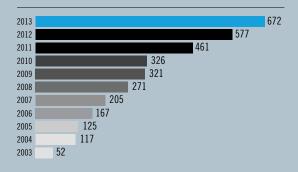
FINANCIAL AND OPERATIONAL HIGHLIGHTS

FINANCIAL OVERVIEW For the years ended December 31 (in thousands of Canadian dollars, except as noted)	2013 ¹	2012 ¹	2011 ²	2010 ²	2009 ³
Power generated (MWh) Revenues Adjusted EBITDA ⁴ Dividend declared - \$ per Series A preferred share Dividend declared - \$ per Series C preferred share ⁵ Dividend declared - \$ per common share	2,381,820	2,104,945	1,905,426	1,227,435	823,989
	198,259	176,655	148,260	91,385	58,625
	148,916	133,792	111,196	68,111	46,778
	1.25	1.25	1.25	0.42	-
	1.57	-	-	-	-
	0.58	0.58	0.58	0.61	0.68

- 1 Prepared in accordance with IFRS exclude joint ventures (IFRS 11).
- 2 Restated in accordance with IFRS include ioint ventures.
- 3 Prepared in accordance with Canadian GAAP include joint ventures.
- 4 Defined as revenues less operating expenses, general and administrative expenses, and prospective project expenses.
- 5 The initial dividend payment was higher to reflect dividends accruing since the closing date of the Series C preferred share offering of December 11, 2012. The regular annual dividend amount is \$1.4375.

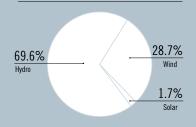
NET INSTALLED CAPACITY

At December 31 (MW)



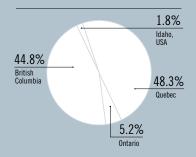
ENERGY SOURCE DIVERSIFICATION

Based on actual consolidated production

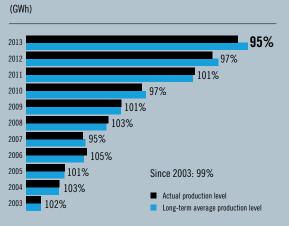


GEOGRAPHIC DIVERSIFICATION

Based on actual consolidated production

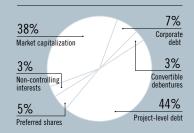


PRODUCTION PREDICTABILITY



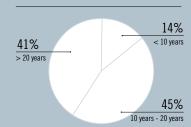
CAPITAL STRUCTURE

At December 31



PPA REMAINING TERMS

Based on consolidated annualized long-term average production of operating facilities

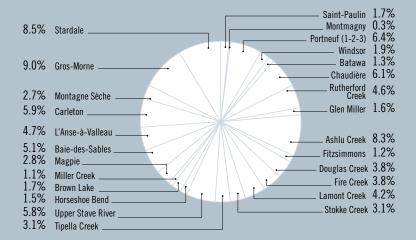


PROJECTS UNDER DEVELOPMENT	PROJECT	LOCATION	GROSS CAPACITY (MW)	INNERGEX'S OWNERSHIP	ESTIMATED CONSTRUCTION COSTS (\$M)	EXPECTED IN-SERVICE DATE
WIND	Mesgi'g Ugju's'n	QC	150.0	50.0%	365.0 ¹	2016
HYDRO	Tretheway Creek Boulder Creek Upper Lillooet River Big Silver Creek	BC BC BC BC	23.2 25.3 81.4 40.6	100.0% 66.7% 66.7% 100.0%	111.5 119.2 315.0 216.0	2015 2015 2016 2016

¹ Preliminary estimate. Subject to change.

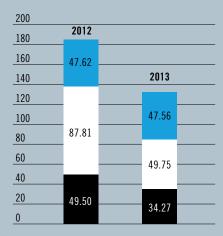
REVENUE BREAKDOWN BY SITE

Based on 2013 Revenues



CASH AND RESERVE ACCOUNTS

At December 31 (\$M)



- Reserve accounts
- Restricted cash and short-term investments
- Cash and cash equivalents

2013 HIGHLIGHTS

Electricity production increased by year-over-year

Revenues rose 12% to

payout ratio

Three projects completed

completed

Total net installed capacity increased 16% to

number of operating facilities

proportion of energy produced from hydro The electricity we produced was enough to power

Canadian households

in project financing secured

REPORT CARD

As in the past, we will continue to carry out our ambitious development program, maintain a balanced capital structure, and pursue growth opportunities.

PERFORMANCE	2012	2013	2014
Power generated ¹	2,105 GWh +13%	2,382 GWh +13%	Approx. +20%
Revenues ¹ Adjusted EBITDA ¹	\$176.7M +22% \$133.8M +24%	\$198.3M +12% \$148.9M +11%	Approx. +20% Approx. +20%
Adjusted Editor	Ψ133.0₩	φ140.JW +1170	ημριολ. +2076
Number of facilities in operation at year-end ²	28	32	32
Net installed capacity at year-end ²	577 MW	672 MW	672 MW
Consolidated long-term average production, annualized ^{1,2}	2,407 GWh	2,883 GWh	2,883 GWh

¹These figures exclude the Umbata Falls and Viger Denonville facilities that are treated as joint ventures and are accounted for using the equity method.

WE SAID WE WOULD

PERFORMANCE

Increase power generated, revenues and Adjusted EBITDA by approximately 10% as a result of the full-year contribution from the Stardale solar farm commissioned in May 2012 and the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, and the addition of capacity at the Gros-Morne wind farm in November 2012. Growth targets increased to approximately 15% in July 2013 when the Magpie acquisition closed.

Increase the number of operating facilities at year-end from 28 to 31 as a result of commissioning the Kwoiek Creek and Northwest Stave River hydroelectric projects and the Viger-Denonville wind project.

Increase net installed capacity at year-end from 577 MW to 631 MW for the reasons noted above.

Increase annualized consolidated long-term average production by 9% to 2,684 GWh for the reasons noted above.

FINANCING

Finance the Northwest Stave River hydroelectric project in the amount of approximately \$75M

Refinance the Carleton wind farm in the amount of approximately \$42M

Finance the Viger-Denonville wind project in the amount of approximately \$55M

Finance the Upper Lillooet River and Boulder Creek hydroelectric projects in the amount of approximately \$370M

WE DID

- Power generated increased by 13%, while revenues increased 12% and Adjusted EBITDA increased 11% as a result of the full-year contribution from the Stardale solar farm commissioned in May 2012 and the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, the addition of capacity at the Gros-Morne wind farm in November 2012, as well as the contribution of the Magpie hydroelectric facility acquired in July 2013, which accounted for an increase of approximately 5% in electricity produced and 3% in revenues.
- The Company has 32 operating facilities following the commissioning of the Viger-Denonville, Kwoiek Creek and Northwest Stave River facilities, as well as the addition of the Magpie hydroelectric facility acquired in July 2013.
- Net installed capacity stands at 672 MW for the reasons noted above.
- Annualized consolidated long-term average production has increased by 20% to 2,883 GWh for the reasons noted above, as well as adjustments to the LTA of newly commissioned facilities, and excluding the Umbata Falls joint venture.
- On May 23, Innergex closed a financing of \$72M with an interest rate of 5.3% and a 40-year term for the Northwest Stave River hydroelectric project.
- On June 26, Innergex closed a financing of \$52.8M with an interest rate of 5.6% and a 14-year term for the Carleton wind farm.
- On August 7, the Company and its joint venture partner closed a financing of \$61.7M with an interest rate of 6.0% and an 18-year term for the Viger-Denonville wind project.
- Innergex did not secure the financing for these projects, mainly as a result of construction beginning in the latter half of the year. However, in Q3 it began a hedging program to fix the interest rate on these project-level debts. This hedging program was essentially completed in January 2014.

WE EXPECT TO

Innergex expects power generated, revenues and Adjusted EBITDA to increase by approximately 20% as a result of the full-year contribution of the Magpie hydroelectric facility acquired in July 2013 and the full-year contribution of the Northwest Stave River and Kweiek Creek hydroelectric facilities commissioned at the end of 2013. The Viger-Denonville wind farm is a joint venture and accounted for using the equity method; therefore, it is excluded from these figures.

The number of operating facilities is expected to remain unchanged, as projects currently under development are expected to be completed between 2015 and 2016. This excludes potential acquisitions.

The net installed capacity at year-end is expected to remain unchanged for the reasons noted above. This excludes potential acquisitions.

Annualized consolidated long-term average production is expected to remain unchanged for the reasons noted above. This excludes potential acquisitions.

The Company intends to conclude the financing for the cluster comprising the Upper Lillooet River hydroelectric project and the Boulder Creek hydroelectric project in the amount of approximately \$370M during 2014.

² Figures for 2013 include the Northwest Stave River and Kwoiek Creek hydroelectric facilities that were completed on time and on budget in December 2013 and were commissioned effective December 18, 2013 and January 1, 2014, respectively.

WE SAID WE WOULD **WE DID WE EXPECT TO** Finance the Tretheway Creek and Big Silver The Company intends to conclude the financing for the Innergex did not secure the financing for these projects, mainly as Creek hydroelectric projects in the amount of a result of construction beginning in the latter half of the year at Tretheway Creek hydroelectric project in the amount of Tretheway Creek and being postponed until spring 2014 for Big approximately \$70M during 2014 and for the Big Silver Creek approximately \$220M Silver Creek. However, in Q3 it began a hedging program to fix the hydroelectric project in the amount of approximately \$150M in interest rate on these project-level debts. This hedging program was late 2014 or early 2015. essentially completed in January 2014. The Company extended its \$425M revolving term credit facility Extend the revolving term credit facility No projections were made at the beginning to 2018, with enhanced usage flexibility and the same terms of the year. and conditions as before Innergex intends to enter into a hedging program to fix the interest rate on the project-level debt for the Mesgi'g Ugju's'n The Company and its joint venture partner intend to refinance the Umbata Falls hydroelectric facility in the amount of approximately \$47M in view of the upcoming term of the initial project financing. PROJECT DEVELOPMENT The Kwoiek Creek hydroelectric facility was completed on time **Commission the Kwoiek Creek hydroelectric** facility in Q4 and on budget in December 2013 and was commissioned effective January 1. The Northwest Stave River hydroelectric facility was completed **Commission the Northwest Stave River** hydroelectric facility in Q4 on time and on budget in December 2013 and was commissioned effective December 18 Begin construction in the spring and Construction of the Viger-Denonville wind farm began in the spring; commission the Viger-Denonville wind the project was completed on time and under budget, and was commissioned on November 19. A planned \$7M capital improvement program to coat the penstock, Complete the capital improvements program at the Miller Creek hydroelectric facility reshape the intake and replace some turbine components was in the fall completed on schedule and on budget in early November 2013. As a result, the long-term average production of the Miller Creek facility has increased by 5%. **Begin construction of the Tretheway Creek** Innergex began construction of the Tretheway Creek hydroelectric The Company intends to proceed with the construction of the and Big Silver Creek hydroelectric projects facility during the fourth quarter. It has postponed construction of Tretheway Creek hydroelectric facility throughout the year and the Big Silver Creek facility until the spring of 2014 with no impact to begin construction of the Big Silver Creek hydroelectric on the expected start of commercial operation, since the enginfacility eering, procurement and construction contractor and the turbine in the spring. supplier had not been selected before winter. Begin construction of the Upper Lillooet River Innergex began construction of the Upper Lillooet River and Boulder The Company intends to proceed with the construction of the and Boulder Creek hydroelectric projects Creek hydroelectric projects during the fourth quarter. Upper Lillooet River and Boulder Creek hydroelectric projects throughout the year. The Company and its First Nations partner intend to sign a power purchase agreement and proceed with the development and permitting of the Mesgi'g Ugju's'n wind project, with the intention of starting construction in 2015. Innergex intends to submit a number of potential wind projects under Hydro-Québec's 450 MW request for proposals by the September 2014 deadline. Innergex intends to renew the power purchase agreement for the Saint-Paulin hydroelectric facility for a second 20-year term. **EXTERNAL GROWTH OPPORTUNITIES** Complete the acquisition of the Magpie The acquisition of the Magpie hydroelectric facility closed hydroelectric facility from Hydroméga Group on July 25. of Companies Complete the acquisition of other Hydroméga The Company continued to make progress on negotiations with Innergex intends to complete the acquisition of other assets under a letter of intent Hydroméga to acquire other assets under its letter of intent. Hydroméga assets under terms that will ensure such acquisitions are accretive

■ Innergex remained active and disciplined in studying several

its risk profile and return requirements.

potential acquisition targets throughout the year. It did not succeed in finding an acquisition under terms and conditions that satisfied

Pursue M&A opportunities that contribute

immediately to cash flow generation

return requirements.

The Company intends to pursue M&A opportunities that correspond to its stated mission and contribute to cash

flow generation while satisfying its risk profile and

FORWARD-LOOKING INFORMATION IN THIS DOCUMENT

The following table outlines certain Forward-Looking Information, as described on the inside cover and contained in this document, that the Company considers important to better inform readers about its potential

financial performance. Also included are the principal assumptions used to derive this information and the principal risks and uncertainties that could cause actual results to differ materially from it.

PRINCIPAL ASSUMPTIONS

EXPECTED PRODUCTION

For each facility, the Company 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 limitations, 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 LTA. On a consolidated basis, the Company 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).

PRINCIPAL RISKS AND UNCERTAINTIES

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 & 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 Company 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 inflation rate than expected

PRINCIPAL ASSUMPTIONS

PROJECTED ADJUSTED EBITDA

For each facility, the Company estimates annual operating earnings by subtracting from the estimated revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operations and maintenance expenditures, property taxes, and royalties; these are predictable and relatively fixed, varying mainly with inflation except for maintenance expenditures. On a consolidated basis, the Company estimates annual Adjusted EBITDA by adding together the projected operating earnings of all the facilities in operation that it consolidates*, from which it subtracts budgeted general and administrative expenses, comprised essentially of salaries and office expenses, and budgeted prospective project expenses, which are determined based on the number of prospective projects the Company chooses to develop and the resources required to do so.

* Excludes Umbata Falls and Viger-Denonville accounted for using the equity method.

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 Company 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 projected costs provided by the engineering, procurement and construction (EPC) contractor retained for the project.

The Company 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.

PRINCIPAL RISKS AND UNCERTAINTIES

Variability of facility performance and related penalties

Changes to water and land rental expenses

Number of prospective projects in activity

Unexpected maintenance expenditures

Performance of counterparties, such as the EPC contractors

Delays and cost overruns in the design and construction of projects

Obtention of permits

Equipment supply

Interest rate fluctuations and availability of financing

Relationships with stakeholders

Regulatory and political risks

EXPECTED PROJECT FINANCING OR REFINANCING OF OPERATING FACILITIES

The Company 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 LTA production and expected costs of each project, the expected remaining power purchase agreement term, a leverage ratio of approximately 75%-85%, as well as the Company's extensive experience in project financing and knowledge of the capital markets.

Interest rate fluctuations and availability of financing

Financial leverage and restrictive covenants governing current and future indebtedness

INTENTION TO SUBMIT PROJECTS UNDER REQUESTS FOR PROPOSALS

The Company provides indications of its intention to submit projects under requests for proposals (RFP) based on the state of readiness of some of its prospective projects and their compatibility with the announced terms of the RFP.

Regulatory and political risks

Ability of the Company to execute its strategy

Ability to secure new power purchase agreements

INFORMATION FOR INVESTORS

COMMON SHARES (TSX: INE)

Innergex Renewable Energy Inc. had 95,654,911 common shares outstanding at December 31, 2013, with a closing price of \$10.60 per share. The company's shares are listed on the Toronto Stock Exchange.

SERIES A PREFERRED SHARES (TSX: INE.PR.A)

Innergex Renewable Energy Inc. currently has 3,400,000 Series A preferred shares outstanding, with a nominal value of \$25 and a fixed cumulative preferential annual cash dividend of \$1.25 per share, payable quarterly on the 15th day of January, April, July, and October. Series A preferred shares are not redeemable by the company prior to January 15, 2016.

SERIES C PREFERRED SHARES (TSX: INE.PR.C)

Innergex Renewable Energy Inc. currently has 2,000,000 Series C preferred shares outstanding, with a nominal value of \$25 and a fixed-rate cumulative preferential annual cash dividend of \$1.4375 per share, payable quarterly on the 15th day of January, April, July, and October. Series C preferred shares are not redeemable by the company prior to January 15, 2018.

CONVERTIBLE DEBENTURES (TSX: INE.DB)

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for a total notional amount of \$80.5 million, which bear interest at an annual rate of 5.75% and mature on April 30, 2017. Each convertible debenture is convertible into common shares of the company at a price of \$10.65 per share at the holder's option at any time prior to the earlier of April 30, 2017 or the redemption date specified by the company. The convertible debentures are subordinated to all other indebtedness of the company.

TRANSFER AGENT AND REGISTRAR

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents (such as quarterly and annual reports and proxy circulars), please contact the company's transfer agent and registrar:

Computershare Investor Services Inc.

1500 University Street, Suite 700
Montreal, Quebec, Canada H3A 3S8
Phone: 1 800 564-6253 or 514 982-7555
Email: service@computershare.com
Website: computershare.com

DIVIDEND REINVESTMENT PLAN (DRIP)

Innergex Renewable Energy Inc. offers a Dividend Reinvestment Plan (DRIP) for its common shareholders. This plan enables eligible holders of common shares to acquire additional common shares of the company by reinvesting all or part of their cash dividends. For more information about the company's DRIP, please visit our website at www.innergex.com or contact the DRIP administrator, Computershare Trust Company of Canada. Please note that if you wish to enrol in the DRIP but own your shares indirectly through a broker or financial institution, you must contact this intermediary and ask them to enrol in the DRIP on your behalf.

CREDIT RATINGS

	STANDARD & POOR'S	DBRS ¹
Innergex Renewable Energy Inc.	BBB-	BB (high)
Series A Preferred Shares	P-3	Pfd-4 (high)
Series C Preferred Shares	P-3	Pfd-4 (high)
Convertible Debentures		

¹Unsolicited Rating

S&P/TSX

The Company is included in the following indices:

- S&P/TSX Composite Index
- S&P/TSX Composite Dividend Index
- S&P/TSX Equity Income Index
- S&P/TSX Composite Low Volatility Index
- S&P/TSX SmallCap Index
- S&P/TSX Renewable Energy and Clean Technology Index

Innergex's strategy for building shareholder value is to develop or acquire high-quality facilities that generate sustainable cash flows and provide a high return on invested capital, and to distribute a stable dividend.

INVESTOR RELATIONS

To obtain additional financial information, company updates, or recent news releases and investor presentations, please contact:

Marie-Josée Privyk, CFA, SIPC

Director — Investor Relations Tel.: 450 928-2550, mjprivyk@innergex.com

Or visit www.innergex.com

Ce document est disponible en français.
Pour la version numérique, visitez notre site Web à www.innergex.com.
Pour la version papier, communiquez avec nous à info@innergex.com.





MANAGEMENT'S DISCUSSION AND ANALYSIS AND CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2013



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

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 year ended December 31, 2013, and reflects all material events up to February 25, 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 audited consolidated financial statements and the accompanying notes for the year ended 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 audited consolidated financial statements attached to this MD&A and the accompanying notes for the year ended December 31, 2013, along with the 2012 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.

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

The President and Chief Executive Officer and the Chief Financial Officer 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 evaluated the effectiveness of the Corporation's DC&P and ICFR as at December 31, 2013, and have concluded that they were effective and that there were no material weaknesses relating to the DC&P and ICFR for the year ended December 31, 2013. During the year ended December 31, 2013, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

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

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 recently announced acquisitions, of its ability to sustain current dividends and dividend increases and 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; its ability to access sufficient capital resources; liquidity risks related to derivative financial instruments; changes in hydrology, wind regime and solar irradiation; delays and cost overruns in the design and construction of projects; health, safety and environmental risks; the ability to develop new facilities; obtainment of permits; variability of installation performance and related penalties; equipment failure; interest rate fluctuations and refinancing risk; financial leverage and restrictive covenants governing current and future indebtedness; declaration of dividends at the discretion of the board; the ability to secure new power purchase agreements; the ability to retain senior management and key employees; litigation; performance of major counterparties; relationships with stakeholders; equipment supply; regulatory and political changes: the ability to secure appropriate land; reliance on power purchase agreements; reliance on shared transmission and interconnection infrastructure; water and land rental expense; assessment of water, wind and sun resources and associated electricity production; dam safety; natural disasters and force majeure; foreign exchange fluctuations; sufficiency of insurance coverage; a credit rating that may not reflect actual performance of the Corporation; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired; failure to realize the anticipated benefits of acquisitions; the inability to execute a definitive agreement and close the acquisition of the Hydroméga hydroelectric facilities and Development Project: the introduction of solar photovoltaic power facility operation; and fluctuations in the revenues from the Miller Creek facility based on the Mid-C spot price for 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.

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

Forward-Looking Information in this MD&A

The following table outlines Forward-Looking Information contained in this MD&A, that 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 consolidated (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 & 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 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 inflation rate than expected
Projected Adjusted EBITDA	
For each facility, the Corporation estimates annual operating earnings by subtracting from the estimated revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operations and maintenance expenditures, property taxes, and royalties; these are predictable and relatively fixed, varying mainly with inflation except for maintenance expenditures. On a consolidated basis, the Corporation estimates annual Adjusted EBITDA by adding the projected operating earnings of all the facilities in operation that it consolidates*, from which it subtracts budgeted general and administrative expenses, comprised essentially of salaries and office expenses, and budgeted prospective project expenses, which are determined based on the number of Prospective Projects the Corporation chooses to develop and the resources required to do so.	Variability of facility performance and related penalties Changes to water and land rental expenses Number of Prospective Projects in activity Unexpected maintenance expenditures
*Excludes Umbata Falls and Viger-Denonville accounted for using the equity method.	
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 projected costs provided by the engineering, procurement and construction (EPC) contractor retained for the project.	Performance of counterparties, such as the EPC contractors Delays and cost overruns in the design and construction of projects Obtainment of permits Equipment supply Interest rate fluctuations and availability of
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.	financing Relationships with stakeholders Regulatory and political risks
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 LTA production and expected costs of each project, the expected remaining PPA term, a 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 availability of financing Financial leverage and restrictive covenants governing current and future indebtedness
Intention to submit projects under requests for proposals	Regulatory and political risks
The Corporation provides indications of its intention to submit projects under requests for proposals (RFP) based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these RFPs.	Ability of the Corporation to execute its strategy Ability to secure new power purchase agreements

(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:

- 32 facilities that are in commercial operation (the "Operating Facilities"). Commissioned between November 1994 and
 January 2014, the facilities have a weighted average age of approximately 5.9 years. They sell the generated power
 under long-term Power Purchase Agreements ("PPA") that have a weighted average remaining life of 20.2 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 three 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 ("RFP") or a Standing
 Offer Program ("SOP") (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.



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 results of operations, 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, as well as adjustments that represent 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 derivate 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 generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods.

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 25 hydroelectric facilities, which draw on 22 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 %	Q.	1	Q	2	Q:	3	Q	4	Total		
HYDRO	278.0	13%	774.1	36%	680.7	31%	435.6	20%	2,168.4		
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	498.9	17%	929.4	32%	806.2	28%	648.7	22%	2,883.3		

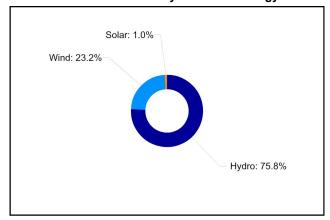
^{1.} Annualized long-term average production ("LTA") for the facilities in operation at February 25, 2014. The LTA production is presented in accordance with revenue recognition accounting rules under IFRS and excludes production from facilities that are accounted for using the equity method, which 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)

Seasonality of LTA by Quarter

Breakdown of LTA by Source of Energy



Strategic Relationships

The Corporation often teams up with a strategic or financial partner. When this is the case, the Corporation and the partner share the ownership of projects concerned. The current strategic partners are TransCanada Energy Ltd. (owner of 62% of the Baie-des-Sables, L'Anse-à-Valleau, Carleton, Montagne Sèche and Gros-Morne wind farms), the Ojibways of the Pic River First Nations (owner of 51% of the Umbata Falls facility), the Kanaka Bar Indian Band (owner of 50% of the Kwoiek Creek facility), the Rivière-du-Loup Regional County Municipality ("RCM") (owner of 50% of the Viger-Denonville community wind farm), Ledcor Power Group Ltd. (owner of 33¹/₃% of the Fitzsimmons Creek facility, the Boulder Creek and Upper Lillooet River Development Projects as well as other Creek Power Inc. Prospective Projects), the Mi'gmawei Mawiomi (or the "Mi'gmaq communities of Quebec") (owner of 50% of the Mesgi'g Ugju's'n wind Development Project) and the Minganie Regional County Municipality (owner of 0.001% of the common units and 30% of the voting units of the Magpie hydroelectric facility). Current financial partners include CC&L Harrison Hydro Project Limited Partnership and LPF (Surfside) Development L.P. (owners of 34.99% and 15.00% of Harrison Hydro L.P. respectively).

Opportunities for Organic Growth

Growing awareness and concern over issues such as access to clean energy, energy security, energy efficiency and the environmental impacts of conventional fossil fuels are leading the federal and provincial governments to increase their demand for and commitments to the development of the renewable energy supply. Consequently, the Corporation believes that the outlook for the renewable energy industry in Canada is promising.

The Corporation is confident that RFP opportunities will continue to arise in the future, especially in Quebec, British Columbia and Ontario, as these provinces have been very proactive in the procurement of renewable power generation. While the Corporation has historically focused its bidding activities on RFPs issued in these three provinces, where it has experienced a good level of success, it continues to monitor the situation in other provinces where opportunities may arise.

In Quebec, Hydro-Québec launched a request for proposals in December 2013 for the procurement of 450 MW of new wind energy, including 300 MW for projects in the Lower Saint Lawrence and Gaspésie regions and 150 MW for projects anywhere in the province. Regulations stipulate a maximum price of \$0.09 per kWh, minimum local content requirements of 60% and a 50% or more ownership of each project by the local community, including municipalities and First Nations. The Corporation has several wind projects that it intends to submit under this request for proposals before the September 2014 deadline.

In Ontario, the government announced in June 2013 that it would no longer procure large renewable energy capacity under the Feed-In Tariff Program ("FIT") for large projects; as a result the Ontario Power Authority discontinued the previously submitted Large FIT project applications for which no contract had been awarded. Instead, Ontario will seek to institute a competitive procurement process which will take into account local needs and considerations, including those of municipalities and First Nations. In Ontario's *Long-Term Energy Plan* released in December 2013, the government reiterated its commitment to investing in renewable energy and declared its intention to launch this new procurement process in the spring of 2014. Planned capacity procurement would target 300 MW of wind energy and 140 MW of solar energy in 2015 and another 300 MW of wind energy and 150 MW of solar energy in 2016, with planned annual revisions. The Corporation has a number of wind and solar projects that it continues to advance in preparation for submissions under a future competitive bid process. Several prospective projects in Ontario, especially in the wind sector, remain predicated on transmission grid expansion in the northern part of the province and represent longer-term growth potential.

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

In British Columbia, BC Hydro released its *Integrated Resource Plan* in November 2013, which calls for a number of measures to meet the expected increase in electricity demand, including the construction of BC Hydro's Site-C 1,100 MW hydroelectric facility and "a set of actions that will support a healthy, diverse clean energy sector and promote clean energy opportunities for First Nations," but provides no specific procurement targets for renewable energy at this time. The province's significant plans to develop its mining and liquefied natural gas ("LNG") sectors may provide development opportunities for the renewable energy sector, especially given the Premier's pledge to produce the "cleanest LNG in the world" and the importance for the population of minimizing greenhouse gas emissions. The Corporation continues to advance the development of several Prospective Projects with an eye to responding to future renewable energy procurement requirements in this province or submitting them under its Standing Offer Program.

In the United States, the Corporation's management team will continue to selectively assess potential opportunities, particularly in light of the current U.S. administration's focus on increasing renewable energy production and the existence of renewable portfolio standards in several states. According to US Energy Information Association (EIA), electricity generation from renewable energy is expected to rise from 12% in 2012 to 16% by 2040. In the short term, generation from renewable resources is expected to grow in response to federal tax credits (although an important tax credit for wind energy was left to expire at the end of 2013) and state-level policies. However, in the long term, renewable generation growth is expected to be driven by increasing cost competitiveness with other non-renewable technologies. Already in 2014, the EIA estimates that wind energy is the second least costly new generation resource after natural gas.

Growth Opportunities Through Acquisitions

The Corporation may also expand through the acquisition of Prospective and Development Projects at varying development stages or of suitable power generating assets already in commercial operation. As it has done in the past, Innergex will continue to focus on hydroelectric, wind and solar power generation facilities. The Corporation could also grow through expansion into other forms of clean and renewable energy production if profitable opportunities arise. While future projects may be located in any region where opportunities exist, the Corporation expects most of its near-term growth opportunities to come from Canada and the United States.

Key Growth Factors

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

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

Capacity for Delivering Results

The Corporation does business in a competitive sector. The experience and dedication of its management team constitute its strongest asset. Through careful management, it has established a track record of completing projects by the commercial operation start date specified in their PPA while adhering to the established construction budgets. The Corporation's employees possess the specialized knowledge and skills necessary to carry out its business. The Corporation can also rely on a network of technical, financial and legal partners and has proved its ability to complement its internal capabilities with an efficient use of external consultants when required. In addition, the Corporation uses the services of several engineering firms to assist with the feasibility analysis of its projects. At as December 31, 2013, the Corporation employed a total of 171 persons (including Cartier Wind Energy employees).

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

MARKET TRENDS

Renewable power producers are involved in the generation of electricity from renewable energy sources including hydro, wind, solar, landfill gas and geothermal sources.

While traditional regulated utilities continue to dominate the North American electricity generation markets, the growing importance of the role played by independent power producers in meeting future electricity needs is now acknowledged and the benefits of their power output have increasingly been recognized by government authorities and other policymakers in recent years.

There are several factors that explain the growing role played by independent power producers in supplying renewable power in North America, including: the growing demand for energy; increasing awareness of the effects of greenhouse gas emissions on climate change and the environment; the increase in government-sponsored incentives to develop renewable energy capacity; the availability of long-term renewable energy purchase contracts with highly creditworthy counterparties, allowing independent power producers to develop new projects in a low-risk environment with the expectation of stable long-term contractual cash flows; the implementation of non-discriminatory access to transmission systems, providing independent power producers with access to regional electricity markets; and the efficiency of independent power producers.

However, the plentiful supply of natural gas in recent years has resulted in low market prices that have increased the attractiveness of this source of energy to produce electricity. Over the short-term, this could impact demand for renewable energy procurement.

Renewable Power in Canada

Over the past few years, the significant growth in renewable power generation in Canada has resulted from: rising electricity and fossil fuel prices; the increased cost of large-scale hydroelectric sites; public concern over nuclear power generation, air quality, and greenhouse gases; improvements in renewable energy technologies; and shorter construction lead times for some renewable energy projects. Renewable electricity generation in Canada is also supported by federal and provincial incentives, such as long-term fixed price contracts, accelerated depreciation and Renewable Portfolio Standards, which are explained below.

In response to the long-term trend toward stronger environmental protection policies, many provincial governments have introduced Renewable Portfolio Standards ("RPS"), which typically set a target for an increased component of renewable energy in their electricity generation supply mix, in order to reduce greenhouse gas emissions over time. These RPS typically reflect the distinct resource issues associated with electricity generation, given the provinces' respective electricity industry structures and geographical conditions. While RPS are sometimes applied and implemented as goals or targets rather than mandatory requirements, provincial authorities or their utilities are using RPS to source renewable generation resources and, in some cases, offer PPAs through competitive bidding processes. The competitive bidding process seeks to ensure that the RPS are achieved at the lowest possible cost and with the highest probability of project completion. By simplifying the negotiation and financing processes and decreasing the transactional costs for obtaining a long-term PPA, these mechanisms can contribute to meeting renewable energy generation goals.

Several provinces have set a specific target percentage of electricity to be generated from renewable sources:

- British Columbia To generate at least 93% of total electricity from clean or renewable resources and to build the
 infrastructure necessary to transmit that electricity;
- Manitoba To develop 1,000 MW of wind energy capacity by 2015. However no development is currently planned;
- New Brunswick To generate 10% of total electricity from renewable resources by 2016 and to have 40% of inprovince electricity sales provided from renewable energy by 2020;
- Newfoundland and Labrador To develop 80 MW of wind energy on the island of Newfoundland. However no development is currently planned and current installed capacity is 55 MW;
- Nova Scotia To generate 25% of total electricity from renewable resources by 2015 and 40% by 2020;
- Ontario To increase hydro energy capacity to 9,300 MW and to develop 10,700 MW of wind, solar and bioenergy installed capacity by 2021;
- Prince Edward Island To develop 500 MW of wind energy capacity by 2013 and to double its RPS to 30% of total electricity from renewable resources by 2013;
- Quebec To develop 4,000 MW of wind energy capacity by 2015 and an additional 100 MW of wind energy for every 1,000 MW of additional hydroelectric power; and
- Saskatchewan To develop 200 MW of wind energy capacity by 2015.

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

Canada enjoys a unique abundance of hydrological resources. With an estimated installed hydroelectric capacity of more than 74,000 MW, it is the second largest hydroelectric energy producer in the world. Furthermore, according to the Canadian Hydropower Association, the country has an undeveloped, technically feasible potential estimated at 163,000 MW. Despite the competition for appropriate sites and the challenges associated with power transmission over great distances, the low operational costs and long project lives of these facilities suggest that hydroelectric power generation will remain a major affordable supply source for many years. Transmission corridors in Canada have traditionally run directly from major generation facilities to major demand centres, meaning that strategic investments in new transmission corridors will play an important role in the development of hydroelectric projects and other isolated renewable energy generation projects.

Over the last few years, according to the National Energy Board, wind power has become commercially viable and emerged as the fastest growing segment of the renewable power industry in Canada. The Canadian Wind Energy Association ranks Canada as the ninth largest producer of wind energy in the world, with an installed wind power capacity of more than 7,800 MW and approximately 1,500 MW per year of new wind energy to be commissioned over the next few years. Several reasons explain the robustness of the wind energy industry, including provincial RPS, relatively short construction timelines, favourable wind resources, including vast shorelines and strong winds throughout a wide range of rural areas, and numerous renewable energy RFPs. The usual challenges of resource availability and transmission exist in Canada and, in some areas, access to transmission lines with available capacity is an economic or regulatory consideration.

A solar energy industry has emerged in Canada in recent years, specifically in Ontario. In October 2013, the Ontario Power Authority reported 814 MW of solar PV installed capacity in commercial operation with an additional 1,184 MW of capacity under development. Changes to the procurement process announced by the Ontario government in 2013, such as the cancellation of renewable energy procurement through large projects under the FIT program, abolition of local content requirements and the future transition to a net-metering system for microFIT projects, have increased uncertainty about the solar industry's future prospects in this province. However, the government has announced its intention to procure 140 MW of new solar energy in 2015 and another 150 MW in 2016. In addition, production costs continue to decline year after year.

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

SELECTED ANNUAL INFORMATION

	Υ	ear ended December 3	
	2013	2012	2011
		(restated) ³	(restated) ³
Power generated (MWh)	2,381,820	2,104,945	1,869,825
LTA production (MWh)	2,502,562	2,169,182	1,831,119
Revenues	198,259	176,655	144,786
Adjusted EBITDA	148,916	133,792	108,094
Adjusted EBITDA margin	75.1%	75.7%	74.7%
Net earnings (loss)	45,431	(5,383)	(43,704)
Net earnings (loss) attributable to owners of the parent	48,170	1,405	(40,547)
(\$ per common share - basic)	0.43	(0.03)	(0.59)
(\$ per common share - diluted)	0.43	(0.03)	(0.59)
Weighted average number of common shares (in 000s)	94,694	86,557	75,681
Total assets	2,377,074	2,296,440	2,005,469
Long-term debt	1,340,367	1,230,708	1,025,628
Current and other long-term liabilities	290,941	298,145	321,235
Liability portion of convertible debentures	79,831	79,655	79,490
Non-controlling interests	81,429	107,611	114,399
Equity attributable to owners	584,506	580,321	464,717
Dividend declared per Class A Preferred Share	1.25	1.25	1.25
Dividend declared per Class C Preferred Share ¹	1.570425	_	_
Dividend declared per common share	0.58	0.58	0.58
Dividends declared on common shares	54,967	50,693	43,990
Free Cash Flow ²	58,982	43,897	39,024
Payout Ratio ²	93%	115%	113%

^{1.} The regular quarterly dividend is \$0.3593375; the initial dividend was higher to reflect dividends accrued since the closing date of the Series C Preferred Shares offering of December 11, 2012.

Comparison between 2013, 2012 and 2011

For the year ended December 31, 2013, the increases in power generated, revenues and Adjusted EBITDA are attributable mainly to the full-year contribution of the Stardale solar farm commissioned in May 2012, the full-year contribution of the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, the additional capacity at the Gros-Morne wind farm since November 2012 and the acquisition of the Magpie hydroelectric facility in July 2013. The increase from a net loss of \$5.4 million to net earnings of \$45.4 million is due mainly to the reasons mentioned above as well as to a higher unrealized net gain and a smaller realized net loss on derivative financial instruments in 2013 compared with 2012. The increase in long-term debt is attributable mainly to the addition of the Northwest Stave and Magpie project-level debt and the increase in the Carleton debt upon refinancing.

The increases in power generated, revenues and Adjusted EBITDA between 2012 and 2011 are attributable mainly to the full-year contribution of the Cloudworks Acquisition in April 2011 and the commissioning of the Montagne Sèche and Gros-Morne wind farms in November 2011, the commissioning of the Stardale solar farm in May 2012 and the acquisition of the Brown Lake and Miller Creek hydroelectric facilities in October 2012. The decrease in net loss from \$43.7 million to \$5.4 million is due mainly to the reasons mentioned above as well as to higher finance costs and an unrealized net gain on derivative financial instruments, compared with an unrealized net loss in 2011, partly offset by a realized net loss on derivative financial instruments in 2012. The increase in long-term debt is attributable mainly to the Montagne Sèche, Stardale and Kwoiek Creek loans and to drawings on the revolving term credit facility for Gros-Morne. The increase in shareholders' equity is due mainly to issuance of common and preferred shares.

^{2.} For more information on the calculation and explanation of the Corporation's Free Cash Flow and Payout Ratio, please refer to the "Free Cash Flow and Payout Ratio" section.

^{3.} Please refer to the "Accounting Changes" section for a more detailed explanation of the impact of the application of IFRS 11.

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

Impact on net earnings (loss) of the unrealized net gains and	Year ended December 31					
realized net losses on derivative financial instruments	2013	2012	2011			
		(restated)	(restated)			
Net earnings (loss)	45,431	(5,383)	(43,704)			
(Subtract) Add: Unrealized net (gain) loss on derivative financial instruments	(45,249)	(7,791)	58,567			
Add: Realized net loss on derivative financial instruments	3,259	14,127	_			
Add (Subtract): Income tax provision related to above items	11,127	(1,647)	(15,813)			
(Subtract) Add: Share of unrealized and realized net gain or loss on derivative financial instruments of joint ventures, net of related						
income tax provision	(1,951)	(408)	2,126			
	12,617	(1,102)	1,176			

Excluding the realized net losses and the unrealized net gains on derivative financial instruments and the related income taxes, the net earnings for the year ended December 31, 2013, would have been \$12.6 million, compared with a net loss of \$1.1 million in 2012 and net earnings of \$1.2 million in 2011.

2013 DEVELOPMENTS

Innergex Partner Allocated 150 MW for a Wind Project (Mesgi'g Ugju's'n)

On May 10, 2013, the Mi'gmaq communities of Quebec, with whom the Corporation has a partnership agreement, were allocated 150 MW by the Quebec government for a wind energy project in the Gaspé Peninsula. In December 2013, the partners signed a letter of intent with Hydro-Québec Distribution for a 20-year power purchase agreement subject to an order-in-council by the Quebec government. For more information on the Mesgi'g Ugju's'n project, please refer to the "Development Projects" section.

Closing of Northwest Stave River Hydroelectric Project Financing

On May 23, 2013, the Corporation closed a \$72.0 million non-recourse construction and term project financing for the Northwest Stave River hydroelectric facility in British Columbia. The \$72.0 million construction loan carries a fixed interest rate of 5.3%; in the months following the start of the project's commercial operation, it will convert into a 40-year term loan and the principal will begin to be amortized over a 35-year period starting in the sixth year. The financing was arranged by Industrial Alliance Insurance and Financial Services Inc. as agent and lead lender and includes Stonebridge Infrastructure Debt Fund I L.P. as lender.

Extension of the Revolving Term Credit Facility to 2018

On June 17, 2013, the Corporation extended its \$425.0 million revolving term credit facility with a new five-year term ending in 2018. The revolving term credit facility is supported by 13 of the Corporation's otherwise unencumbered Operating Facilities and provides a flexible source of capital to fund the Corporation's growth. The terms and conditions remained unchanged while usage flexibility was enhanced. The banking syndicate for the facility also remained unchanged and includes Toronto-Dominion Bank as administrative agent and lender, Bank of Montreal as syndication agent and lender and Canadian Imperial Bank of Commerce, Caisse centrale Desjardins, National Bank of Canada, Bank of Nova Scotia and Laurentian Bank of Canada as additional lenders.

Carleton Wind Farm Refinancing

On June 26, 2013, the Corporation closed a \$52.8 million non-recourse term loan to refinance its ownership portion of the Carleton wind farm in Quebec, Canada. The term loan carries a fixed interest rate of 5.6% (through the use of swaps) and the principal will be amortized over a term of approximately 14 years, which is slightly shorter than the remaining duration of the wind farm's first power purchase agreement. Additional proceeds from the refinancing of approximately \$11.7 million were used essentially to reduce drawings on the Corporation's revolving term credit facility. The higher refinancing amount results from the wind farm performing better than initially expected by the lenders. The refinancing as well as the swap agreement to fix the interest rate have been provided by the same two lenders, namely Sumitomo Mitsui Banking Corporation and Bank of Tokyo Mitsubishi UFJ Canada.

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

Interest Rate Hedging Program

In 2013, the Corporation began a hedging program using derivative financial instruments in order to lock-in interest rates for the future financing of five Development Projects until it closes the project-level financing. As at the date of this MD&A, this hedging program was essentially complete for four of the five Development Projects, effectively eliminating these projects' exposure to interest rate fluctuations.

Closing of the Magpie Acquisition

On July 25, 2013, the Corporation completed the previously announced acquisition of an interest in the Magpie facility in Quebec from the Hydroméga Group of Companies. Magpie is a 40.6 MW run-of-river hydroelectric facility located on Crown lands in the Minganie Regional County Municipality in Northeastern Quebec. This facility began commercial operation in 2007 and all of the electricity it produces is sold to Hydro-Québec under a 25-year fixed-price power purchase agreement, which provides for an annual 1% increase in the selling price. Magpie has an average annual production of approximately 185,000 MWh, enough to power almost 11,000 Quebec households each year.

Acquisition of Other Hydroméga Assets

Concurrent with the announcement of the Magpie acquisition in July 2012, the Corporation signed a letter of intent with Hydroméga to acquire its ownership interest in several other assets, including a 30.5 MW hydroelectric facility in Quebec, four hydroelectric projects now in operation totaling 22.0 MW in Ontario and a 10.0 MW hydroelectric project under construction also in Ontario. The Corporation continues to advance negotiations with Hydroméga to acquire other assets, while ensuring that any such acquisition will be accretive.

Closing of the Viger-Denonville Wind Project Financing

On August 7, 2013, Parc éolien communautaire Viger-Denonville, s.e.c. ("Viger-Denonville, L.P.") closed a \$61.7 million non-recourse construction and term project financing for the Viger-Denonville wind farm in Quebec. The \$61.7 million construction loan carries a fixed interest rate of 6.0% (through the use of a swap) since December 31, 2013. In the months following the start of the project's commercial operation, it will convert into a term loan amortizing over 18 years. Viger-Denonville, L.P. has also closed a \$5.5 million short-term loan with a floating interest rate to finance the construction of the substation and collector system, for which it is entitled to be reimbursed by Hydro-Québec in 2014. These loans have been arranged by KfW IPEX-Bank GmbH as agent and lender.

Concurrent with the closing of the financing, Viger-Denonville, L.P. settled the bond forward contracts used to hedge the interest rate on the debt and therefore protect the expected returns on the project, giving rise to a \$2.2 million realized gain on derivative financial instruments. This is equivalent to a fixed interest rate of approximately 5.5% on the loan.

Changes to the Dividend Reinvestment Plan (DRIP)

In view of market conditions that prevailed during the better part of 2013, the Corporation elected to eliminate the 2.5% discount applicable to the purchase price of shares issued to shareholders participating in the DRIP. Therefore, shares purchased under the DRIP will continue to be issued from treasury and the price will be the weighted-average trading price of the common shares on the Toronto Stock Exchange during the five (5) business days immediately preceding the dividend payment date. This change came into effect on August 8, 2013. Any decision by the Corporation to change either the purchase method for the shares or the discount granted on the purchase price of shares issued from treasury will be communicated by press release.

Capital improvement program at the Miller Creek hydroelectric facility

In early November 2013, the Corporation completed as planned a capital improvement program of approximately \$7.0 million at the 33.0 MW Miller Creek hydroelectric facility in British Columbia. Work involved surface preparation and coating of the penstock, redesigning and reshaping the intake to reduce sand and sediment intrusion and improve hydraulic performance and replacing some turbine components. This capital improvement program was completed on time and on budget and the facility, which was shut down on August 12, was restarted on November 13. As a result of these improvements, the facility's long-term average annual production increased by approximately 5%, from 97,900 MWh to 102,795 MWh. This capital expenditure program was announced at the time of the acquisition and was initially expected to occur in the fall of 2012. It was later postponed to the fall of 2013 due to the longer-than-expected acquisition closing process, seasonal constraints and contractor availability. Funding for this program has been provided by the proceeds of the \$123.7 million private placement concluded in July 2012 and was considered in establishing the purchase price for the Miller Creek acquisition.

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

Commissioning of the Viger-Denonville Wind Farm

On November 19, 2013, the Corporation and the Rivière-du-Loup Regional County Municipality ("RCM") announced the commissioning of the 24.6 MW Viger-Denonville wind farm in Quebec. For more information on the Viger-Denonville wind farm, please refer to the "Commissioning Activities" and the "Investments in Joint Ventures" sections.

Agreements with Saik'uz First Nation for the development of a wind project

On December 17, 2013, the Corporation signed a Letter of Intent and a Traditional Knowledge Protocol Agreement with the Saik'uz First Nation regarding the development of a wind energy project at Nulki Hills near Vanderhoof, British Columbia. This prospective wind project of up to 210 MW is currently undergoing a BC Environmental Assessment. The partners will work together to obtain an Environmental Assessment Certificate from the province and an electricity purchase agreement from BC Hydro for this project, which could deliver power to the grid as early as 2018.

Addition to the S&P/TSX Composite Index

On December 20, 2013, the Corporation was added to the S&P/TSX Composite Index as well as to the S&P/TSX Composite Dividend Index, the S&P/TSX Equity Income Index and the S&P/TSX Composite Low Volatility Index. These changes were made by S&P Dow Jones Indices LLC following the latest quarterly review of the S&P/TSX Canadian indices it provides.

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

COMMISSIONING ACTIVITIES

The following table presents the Operating Facilities that have been commissioned during the year:

				Gross	PPA	Total project costs		Expected year-one	
PROJECTS COMMISSIONED	Ownership %	installed capacity (MW)	COD ¹	COD ¹ estimated LTA ² (GWh)		Estimated ² (\$M)	As at Dec. 31 (\$M) ⁴	Revenues ² (\$M)	Adjusted EBITDA ² (\$M)
HYDRO (British Columb	bia)								
Kwoiek Creek	50.0	49.9	1/1/14	223.4	40	153.2 ³	156.0 ³	18.0	15.0
Northwest Stave River	100.0	17.5	18/12/13	63.3	40	91.4	88.7	7.0	6.0
WIND (Quebec)									
Viger-Denonville	50.0	24.6	19/11/13	72.4	20	73.2 ³	64.3 ³	11.0 ³	9.0

^{1.} Commercial operation date.

Kwoiek Creek hydroelectric facility

On February 18, 2014, the Corporation announced that the Kwoiek Creek Resources Limited Partnership had begun operation of the Kwoiek Creek run-of-river hydroelectric facility located near Lytton, British Columbia. Innergex holds 50% of Kwoiek Creek Resources Limited Partnership and is responsible for the management of the construction and the operation of the facility. The Kanaka Bar Indian Band holds the remaining 50% interest. This facility has a gross installed capacity of 49.9 MW and an estimated average annual production of 223,400 MWh. Construction began in 2011 and was completed in early December 2013, on time and on budget. While commissioning of the facility began at that time, the Corporation and BC Hydro have amended their agreement to clarify stipulated production levels, subject to approval by the British Columbia Utilities Commission. Once the approval is received, BC Hydro will accept the COD certificate with an effective commissioning date of January 1, 2014. All of the electricity it produces is sold to BC Hydro under a fixed-price power purchase agreement that provides for an annual adjustment to the selling price based on a portion of the Consumer Price Index and that expires in 2054. In its first full year of operation, it is expected to generate revenues and Adjusted EBITDA of approximately \$18.0 million and \$15.0 million respectively. The Kwoiek Creek Resources Limited Partnership is accounted for as a non-wholly owned subsidiary. Please refer to the "Non-Wholly Owned Subsidiaries" section for more information about this facility's financial results.

Northwest Stave River hydroelectric facility

On February 24, 2014, the Corporation announced it had begun commercial operation of the Northwest Stave River hydroelectric facility located near Mission, British Columbia. This facility has a gross installed capacity of 17.5 MW and an estimated average annual production of 63,300 MWh. Construction began in 2011 and was completed in early December 2013, on time and on budget. Commissioning of the facility began at that time and the COD certificate has now been approved by BC Hydro with an effective commissioning date of December 18, 2013. All of the electricity it produces is sold to BC Hydro under a fixed-price power purchase agreement that provides for an annual adjustment to the selling price based on a portion of the Consumer Price Index and that expires in 2053. In its first full year of operation, it is expected to generate revenues and Adjusted EBITDA of approximately \$7.0 million and \$6.0 million respectively.

Viger-Denonville wind farm

On November 19, 2013, the Corporation announced the beginning of commercial operation of the Viger-Denonville wind farm located in the municipalities of Saint-Paul-de-la-Croix and Saint-Épiphane, Quebec. This wind farm was developed by Parc éolien communautaire Viger-Denonville, s.e.c., a joint venture owned 50/50 by the Corporation and the Rivière-du-Loup Regional County Municipality. The wind farm comprises 12 wind turbines with a gross installed capacity of 24.6 MW and an estimated average annual production of 72,400 MWh. Construction began in the spring of 2013 and was completed in early November, on time and under budget. All of the electricity it produces is sold to Hydro-Québec under a fixed-price power purchase agreement that provides for an annual adjustment to the selling price based on a portion of the Consumer Price Index and that expires in 2033. A ten-year long-term service agreement has been signed with the turbine manufacturer. In its first full year of operation, the facility is expected to generate revenues and Adjusted EBITDA of approximately \$11.0 million and \$9.0 million respectively. The Viger-Denonville, L.P. is a joint venture accounted for using the equity method. Please refer to the "Investments in Joint Ventures" section for more information about this facility's financial results.

^{2.} This information is intended to inform readers of the projects' potential impact on the Corporation's results. Upon commissioning, LTA production 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.

^{3.} Corresponding to 100% of this facility.

^{4.} Costs at December 31, 2013, are not final.

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

DEVELOPMENT PROJECTS

The Corporation currently has five projects (excluding North Creek) that are expected to reach commercial operation between 2015 and 2016.

		Gross		Gross	Gross PPA -		Total project costs		Expected year-one	
CONSTRUCTION % ca	installed capacity (MW)	capacity COD1		term (years)	Estimated ² (\$M)	As at Dec. 31 (\$M)	Revenues ² (\$M)	Adjusted EBITDA ² (\$M)		
HYDRO (British Colum	bia)									
Tretheway Creek	100.0	23.2	2015	81.9	40	111.5	21.6	9.0	7.5	
Upper Lillooet River	66.7	81.4	2016	334.0	40	315.0	30.3	33.0	27.5	
Boulder Creek	66.7	25.3	2015	92.5	40	119.2	7.8	9.0	7.5	
		129.9		508.4		545.7	59.7	51.0	42.5	

^{1.} Commercial operation date.

Tretheway Creek

The construction of this hydroelectric facility began in October 2013. As at the date of this MD&A, installation of the construction camp was completed and clearing and excavation for the intake, powerhouse and penstock were under way. Construction of this facility is progressing as scheduled and budgeted. Estimated project costs have been adjusted from \$108.5 million to \$111.5 million to reflect inflationary pressures on construction costs in British Columbia. During the fourth quarter of 2013, the Corporation began a hedging program in order to fix the interest rate for this project's financing through the use of derivative financial instruments until it closes the project-level financing. This hedging program was essentially completed in January 2014, effectively eliminating the project's exposure to interest rate fluctuations.

Upper Lillooet River, Boulder Creek and North 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, geotechnical investigations at Upper Lillooet River's powerhouse and intake were completed and construction camp preparations at Boulder Creek were underway. Clearing for the joint transmission line was also underway. As planned, construction activities have been halted for the winter period; they will resume in the spring of 2014. Construction of these facilities is progressing on budget. Estimated project costs have been adjusted to reflect a reallocation of costs between the two projects. During the fourth quarter of 2013, the Corporation began a hedging program in order to fix the interest rate for these projects' financing through the use of derivative financial instruments until it closes the project-level financing. This hedging program was essentially completed in January 2014, effectively eliminating the projects' exposure to interest rate fluctuations.

Discussions are ongoing with BC Hydro to obtain its consent to amend the PPAs to increase the installed capacity of the Upper Lillooet River and Boulder Creek projects and to cancel the North Creek project.

^{2.} This information is intended to inform readers of the projects' potential impact on the Corporation's results. Upon commissioning, LTA production 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.

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

DDO IECTO UNDED		Gross		Gross	PPA	Total project costs		Expected year-one	
PROJECTS UNDER PERMIT PHASE	Ownership %	installed capacity (MW)	Expected COD ¹		term (years)	Estimated ² (\$M)	As at Dec. 31 (\$M)	Revenues ² (\$M)	Adjusted EBITDA ² (\$M)
HYDRO (British Columbia	a)								
North Creek ³	66.7	16.0	2016	59.7	40	72.0	_	n/a	n/a
Big Silver Creek	100.0	40.6	2016	139.8	40	216.0	29.2	18.0	15.0
WIND (Quebec)									
Mesgi'g Ugju's'n ("MU")	50.0	150.0	2016	515.0	20	365.0 ⁴	0.9	55.0 ⁴	45.0 ⁴
(excluding North Creek:)		190.6		654.8		581.0	30.1	73.0	60.0

^{1.} Commercial operation date.

- 2. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Upon commissioning, LTA production 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 PPA is signed and the turbine supplier and EPC contractor have been selected. Actual results may vary. Please refer to the "Forward-Looking Information" section for more information.
- 3. On March 14, 2013, the Company announced changes to the configuration of the Boulder Creek, North Creek and Upper Lillooet River hydro projects, which included cancellation of the North Creek project, which is subject to the still-pending consent of BC Hydro. The Corporation is considering whether to continue the development of North Creek as a Prospective Project.
- 4. Corresponding to 100% of this facility.

Big Silver Creek

The project has received its land tenure and water licence from the provincial government. The remaining permits are in the process of being obtained and present no technical obstacles. The turbine and generator supplier has been selected. Construction for this project is expected to begin in the spring of 2014 once a leave to commence construction is obtained. The Corporation is currently negotiating with civil works and transmission line contractors. In light of these negotiations, estimated project costs have been adjusted from \$191.8 million to \$216.0 million to reflect inflationary pressures on construction costs in British Columbia, in particular for the power tunnel. During the fourth quarter of 2013, the Corporation began a hedging program in order to fix the interest rate for this project's financing through the use of derivative financial instruments, until it closes the project-level financing. This hedging program was essentially completed in January 2014, effectively eliminating the project's exposure to interest rate fluctuations.

Mesgi'g Ugju's'n ("MU")

In December 2013, the Corporation and its Mi'gmaq partner signed a letter of intent with Hydro-Québec Distribution for a 20-year fixed-price PPA, which is subject to an order-in-council by the Quebec government. As at the date of this MD&A, open houses have been conducted and an information session was held as part of the province's environmental review process. Negotiations with potential turbine suppliers were under way. Pre-construction activities are expected to start in 2014, construction is expected to start in 2015 and commercial operation is expected to begin at the end of 2016. Upon signing the PPA, the partners intend to enter into a hedging program to fix the interest rate for this project's financing through the use of derivative financial instruments, until they closes the project-level financing.

PROSPECTIVE PROJECTS

All the Prospective Projects, with a combined potential net installed capacity of 2,900 MW (gross 3,125 MW), are in the preliminary development stage. Some Prospective Projects are targeted toward specific future RFPs, such as the current RFP for 450 MW of new wind energy procurement in Quebec or SOPs, while others will be available for future RFPs yet to be announced. There is no certainty that any Prospective Project will be realized. Additional information about the Corporation's facilities and projects can be found in the Corporation's *Annual Information Form*, which is filed on SEDAR at www.sedar.com.

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

OPERATING RESULTS

Production of electricity for the year was 95% of the long-term average due mainly to lower-than-average water flows in British Columbia and the United States.

Revenues increased 12% and Adjusted EBITDA increased 11% in 2013. These increases are due mainly to the full-year contribution of the Stardale solar farm commissioned in May 2012 and the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, the addition of capacity at the Gros-Morne wind farm in November 2012 and the acquisition of the Magpie hydroelectric facility in July 2013.

The Corporation's operating results for year ended December 31, 2013, are compared with the operating results for the same period in 2012.

Electricity Production

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

Year ended		201	3		2012				
December 31	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	467,645	444,014	105%	80.76	350,148	348,430	100%	82.72	
Ontario	83,040	74,544	111%	68.26	64,687	74,544	87%	68.91	
British Columbia	1,062,730	1,221,997	87%	75.73	1,064,889	1,095,126	97%	77.60	
United States	41,956	46,800	90%	71.82	49,552	46,800	106%	67.91	
Subtotal	1,655,371	1,787,355	93%	76.68	1,529,276	1,564,900	98%	78.09	
WIND									
Quebec	686,380	676,490	101%	79.40	542,295	572,734	95%	84.01	
SOLAR									
Ontario	40,069	38,717	103%	420.00	33,374	31,548	106%	349.90	
Total	2,381,820	2,502,562	95%	83.24	2,104,945	2,169,182	97%	83.92	

^{1.} As a result of the application of IFRS 11, the Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; revenues are not included in the Corporation's consolidated revenues and, for the sake of consistency, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

During the year ended December 31, 2013, the Corporation's facilities produced 2,382 GWh of electricity, or 95% of the LTA of 2,503 GWh. Overall, the hydroelectric facilities produced 93% of their LTA. In Ontario and Quebec, water flows have remained better than average at most facilities throughout the year. In British Columbia, above-average water flows at most facilities in the second and third quarter could not compensate for below-average hydrology in the first and fourth quarters, as this province had one of the driest years on record with precipitation approximately 30% below average. Production levels were also affected by a shutdown for capital improvements at the Miller Creek facility between August 8 and November 13. In the United States, water flows remained below average throughout the year, except for the second quarter. Overall, wind farms produced 101% of their LTA, as above-average wind conditions during the third quarter were enough to offset the lower-than-average wind conditions during the first, second and fourth quarters. The Stardale solar farm produced 103% of its LTA, as better-than-average solar irradiation in the second and third quarters compensated for lower production in the first quarter caused by unusually large snowfalls and extremely cold weather that slowed the removal of snow from the solar panels.

The overall performance of the Corporation's facilities for the year ended December 31, 2013, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind and solar power generation.

^{2.} Including all payment adjustments related to the month, day and hour of delivery, to environmental attributes and to the ecoENERGY Initiative, as applicable.

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

Additional Information

Power Purchase Agreements

The 32 Operating Facilities sell the generated power under long-term PPAs to rated public utilities or other creditworthy counterparties. For Operating Facilities in Quebec, Ontario and British Columbia, PPAs include a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery, except for the Miller Creek hydroelectric facility, for which the price is based on a formula using the Platts Mid-C pricing indices (this facility accounted for 1% of revenues in 2013). For the Horseshoe Bend hydroelectric facility located in Idaho, USA, 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission.

Portneuf

In addition to revenue from the power generated at the three Portneuf facilities, the Corporation receives cash payments from Hydro-Québec to compensate for the partial diversion of the water flow that would have otherwise been available to the Corporation's plants. These payments are based on long-term average annual water flows over 20 years. Although these facilities are exempt from annual hydrological variations under the "virtual energy" provisions included in the long-term PPAs with Hydro-Québec, they must remain in operation in order to receive financial compensation. As such, the payments are contingent on turbine availability and maximum production with the water resources made available by Hydro-Québec.

Inflation Protection

Most of the Corporation's PPAs for Operating Facilities include a clause that adjusts for the effects of inflation:

- all PPAs for Quebec hydroelectric facilities except Magpie provide for a CPI-based power rate increase of between 3% and 6% a year;
- the PPA for the Magpie hydroelectric facility provides for a power rate increase of 1% per year;
- the PPAs for the Glen Miller and Umbata Falls hydroelectric facilities provide for an annual power rate adjustment based on 15% of the CPI;
- all PPAs for British Columbia hydroelectric facilities except Kwoiek Creek, Brown Lake and Miller Creek provide for an annual power rate adjustment based on 50% of the CPI;
- the PPA for the Kwoiek Creek hydroelectric facility in British Columbia provides for an annual power rate adjustment based on 30% of the CPI;
- the PPA for the Brown Lake hydroelectric facility in British Columbia provides for a power rate increase of 3% per year;
- · all PPAs for Quebec wind farms provide for an annual power rate adjustment based on approximately 20% of the CPI.

Power Purchase Agreements Coming Up for Renewal

The PPA for the 8.0 MW St-Paulin hydroelectric facility will reach the end of its initial 20-year term during 2014 and the Corporation has sent to Hydro-Québec a notice of automatic renewal of the PPA for an additional 20-year term. Discussions with Hydro-Québec regarding this renewal should be held in the coming months.

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

Financial Results

	Year e	nded D	December 31	
	2013		2012	
			(restated)	
Revenues	198,259 1	100.0%	176,655	100.0%
Operating expenses	33,947	17.1%	28,850	16.3%
General and administrative expenses	11,194	5.6%	9,601	5.4%
Prospective project expenses	4,202	2.1%	4,412	2.5%
Adjusted EBITDA	148,916	75.1%	133,792	75.7%
Finance costs	65,158		62,038	
Other net (revenues) expenses	(392)		15,566	
Depreciation and amortization	69,160		63,765	
Share of earnings of joint ventures ¹	(6,053)		(1,166)	
Unrealized net gain on derivative financial instruments	(45,249)		(7,791)	
Provision for income taxes	20,861		6,763	
Net earnings (loss)	45,431		(5,383)	
Net earnings (loss) attributable to:				
Owners of the parent	48,170		1,405	
Non-controlling interests	(2,739)		(6,788)	
	45,431		(5,383)	
Basic net earnings (loss) per share	0.43		(0.03)	

^{1.} These figures reflect the application of IFRS 11, pursuant to which Umbata Falls and Viger Denonville are treated as joint ventures and the Corporation's interests in these facilities are required to be accounted for using the equity method. Please refer to the "Accounting Changes Impacting the Presentation of Results" and "Investment in Joint Ventures" sections for more information.

Revenues

For the year ended December 31, 2013, the Corporation recorded revenues of \$198.3 million, compared with \$176.7 million in 2012, corresponding to a 12% increase, due mainly to the full-year contribution of the Stardale solar farm commissioned in May 2012 and the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, the addition of capacity at the Gros-Morne wind farm in November 2012 and the acquisition of the Magpie hydroelectric facility in July 2013. These contributions were partly offset by hydroelectricity production levels that were lower in British Columbia and the United States, compared with last year.

Expenses

Operating expenses: consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes, and royalties. For the year ended December 31, 2013, the Corporation recorded operating expenses of \$33.9 million (\$28.9 million in 2012). This 18% increase is due mainly to the Corporation's operating a greater number of facilities in 2013 than in 2012 following the addition of the Stardale solar farm, additional capacity at the Gros-Morne wind farm and the acquisition of the Brown Lake, Miller Creek and Magpie hydroelectric facilities. Increased maintenance and repair activities at some of the Corporation's hydroelectric facilities and wind farms also explain the increase in operating expenses. In particular, the gradual integration of operations and maintenance activities at the Corporation's wind farms upon expiry of the five-year contract with the original equipment manufacturer has resulted, as planned, in a slight increase in the operating expenses for these facilities. In addition, the aggregate payment in respect of water rights for Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River facilities increased by \$1.6 million. This change resulted from the recent unilateral decision by British Columbia's Ministry of Forests, Lands and Natural Resource Operations 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.

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

General and administrative expenses: consist primarily of salaries and office expenses. For the year ended December 31, 2013, general and administrative expenses totalled \$11.2 million (\$9.6 million in 2012). This 17% increase reflects the Corporation's greater number of facilities in operation, partly offset by the lower reclassification of expenses to transaction costs.

Prospective project expenses: include the costs incurred for the development of Prospective Projects. They result from the number of Prospective Projects that the Corporation chooses to advance and the resources required to do so. For the year ended December 31, 2013, prospective project expenses totalled \$4.2 million (\$4.4 million in 2012).

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 year ended December 31, 2013, the Corporation recorded Adjusted EBITDA of \$148.9 million, compared with \$133.8 million for the same period last year, corresponding to an 11% increase. This increase is due mainly to the full-year contribution from the Stardale solar farm commissioned in May 2012 and the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, additional capacity at the Gros-Morne wind farm in November 2012 and the acquisition of the Magpie hydroelectric facility in July 2013. These contributions were partly offset by production levels that were below the LTA, resulting in less revenues being available to absorb operating and general and administrative expenses, which are not directly correlated to production levels. Consequently, the Adjusted EBITDA margin decreased slightly, from 75.7% in 2012 to 75.1% in 2013.

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 and accretion expenses on other liabilities. For the year ended December 31, 2013, finance costs totalled \$65.2 million (\$62.0 million in 2012). This increase is due mainly to higher interest expense on the Stardale financing upon completion of the interest-rate hedging program in September 2012, the addition of project-level debt related to the Magpie acquisition in July 2013, higher amortization of financing fees and higher interest expense on the project-level debt for the Carleton wind farm concluded in June 2013. This increase was partly offset by lower inflation compensation interest on the real-return bonds, which was caused by lower inflation in 2013 compared with the same period last year.

As at December 31, 2013, 98% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (95% as at December 31, 2012). The difference is due mainly to reduced drawings on the revolving term credit facility when compared to December 31, 2012, whereas the swaps outstanding to fix the interest rate on them decreased more slowly.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 5.46% as at December 31, 2013 (5.70% as at December 31, 2012). The decrease stems from the addition of the Northwest Stave River loan that bears a low fixed interest rate of 5.30% and the addition of the Magpie project debt, which bears an all-in interest rate of 4.33%, partly offset by a higher all-in interest rate of 5.79% on the Stardale loan, which has been hedged by an interest rate swap contract since September 2012, and by the refinancing 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.

Other Net (Revenues) Expenses

Other net (revenues) expenses include transaction costs, realized losses on derivative financial instruments, realized gains and losses on foreign exchange, gains on contingent considerations, loan impairment, compensation from a contractor, settlement of claims received in connection with an acquisition, and other net revenues. For the year ended December 31, 2013, the Corporation recorded other net revenues of \$0.4 million (other net expenses of \$15.6 million in 2012). The variation during the year stems mainly from a lower net realized loss of \$3.3 million on settlement of the Northwest Stave River bond forward contracts, compared with a \$14.1 million loss on the Kwoiek Creek bond forward contracts in 2012, lower transaction costs of \$0.6 million (\$2.8 million in 2012), the \$2.0 million claims settlement received and higher other net revenues resulting mainly from interest income on the \$25.0 million deposit with Hydroméga.

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

Depreciation and Amortization

For the year ended December 31, 2013, depreciation and amortization expenses totalled \$69.2 million (\$63.8 million in 2012). This increase is attributable mainly to the larger asset base resulting from the addition of the Stardale solar farm, additional turbines installed at the Gros-Morne wind farm and the acquisition of the Brown Lake, Miller Creek and Magpie hydroelectric facilities. Taken alone, amortization expenses decreased for the year as a result of a change in accounting estimates to amortize intangible assets of the Quebec hydroelectric facilities, which reflects the renewal rights of their PPAs for periods of 20 to 25 years. For more information on changes to the estimates used, please refer to the "Accounting Changes" section.

Share of Earnings in Joint Ventures

For the year ended December 31, 2013, the share of earnings of joint ventures totalled \$6.1 million (\$1.2 million in 2012). This increase is due mainly to higher Adjusted EBITDA resulting from above-average water flows and higher unrealized net gains on derivative financial instruments for the Umbata Falls hydroelectric facility and to positive Adjusted EBITDA following the start of operation and a realized net gain (partly offset by an unrealized loss) on derivative financial instruments for the Viger-Denonville wind farm. 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 to manage the inflation risk. 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 year ended December 31, 2013, the Corporation recognized an unrealized net gain on derivative financial instruments of \$45.2 million, due mainly to the increase in benchmark interest rates since the end of 2012. For the corresponding period of 2012, Innergex also recognized an unrealized net gain on derivative financial instruments of \$7.8 million, due mainly to the increase in benchmark interest rates since December 31, 2011. Realized net gains or losses on derivative financial instruments are found in "Other Net (Revenues) Expenses" above.

In August 2013, the Corporation began 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 projects. As at the date of this MD&A, this hedging program was essentially complete and the Corporation had entered into derivative financial instruments totaling \$405.0 million for the four 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 December 31, 2013, derivatives that will be settled upon closing of financing had a positive market value of \$6.0 million. Also, upon signing a PPA for the Mesgi'g Ugju's'n Development Project, the Corporation and its partner intend to enter into a hedging program to fix the interest rate on the future project-level debt for this project.

Provision for Income Taxes

For the year ended December 31, 2013, the Corporation recorded a current income tax provision of \$2.6 million (\$2.0 million in 2012) and a deferred income tax provision of \$18.2 million (\$4.8 million in 2012). The difference in the deferred income tax provision for the year is due primarily to higher Adjusted EBITDA, a positive net variation in other net revenues or expenses and the larger unrealized net gain on derivative financial instruments, compared with the same period last year.

Non-controlling Interests

For the year ended December 31, 2013, the Corporation allocated losses of \$2.7 million to non-controlling interests (losses of \$6.8 million in 2012). These non-controlling interests are related mostly to the six hydroelectric facilities of Harrison Hydro L.P. (the "Harrison Operating Facilities"), the Creek Power Inc. subsidiaries and the Kwoiek Creek facility. Please refer to the "Non-Wholly Owned Subsidiaries" section for more information. The lower net loss is due mainly to the recognition of greater unrealized gains on derivative financial instruments in 2013 and to a net realized loss on derivative financial instruments in 2012, partly offset by lower Adjusted EBITDA at the Harrison Operating Facilities resulting from below-average production levels compared with the same period last year.

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

Net Earnings (Loss)

For the year ended December 31, 2013, the Corporation recorded net earnings of \$45.4 million (basic and diluted net earnings of \$0.43 per share), compared with a net loss of \$5.4 million (basic and diluted net loss of \$0.03 per share) in 2012.

Main items contributing to the net earnings for the year ended December 31, 2013, compared with a net loss for the corresponding period in 2012						
Main items – Positive impact	Variation	Explanation				
Adjusted EBITDA	15,124	Due mainly to the commissioning of Stardale (May 2012), additional capacity at Gros-Morne (November 2012) and the Brown Lake, Miller Creek (October 2012) and Magpie (July 2013) acquisitions.				
Unrealized net gain on derivative financial instruments	37,458	Due to a greater increase in benchmark interest rates during 2013 than during 2012.				
Other net (revenues) expenses	15,958	Due mainly to a smaller net realized loss of \$3.3 million on the settlement of the Northwest Stave River bond forwards, compared with a net realized loss of \$14.1 million in 2012 on the settlement of the Kwoiek Creek bond forwards, \$2.2 million reduction in transaction costs, and to a \$2.0 million settlement of claims received in 2013.				
Share of earnings of joint ventures	4,887	Due mainly to higher operating earnings from the Umbata Falls facility resulting from production that was higher than the LTA and from higher unrealized and realized gains on derivative financial instruments in 2013 compared with the same period last year.				
Main items – Negative impact	Variation	Explanation				
Depreciation	6,072	Due mainly to the larger asset base resulting from the addition of Stardale, additional turbines at Gros-Morne and the Brown Lake, Miller Creek and Magpie acquisitions.				
Finance costs	3,120	Due mainly to higher interest on the Stardale financing and the Carleton financing and the addition of the Magpie debts.				
Provision for income taxes	14,098	Due to the net variation of the items described above.				

Number of Shares Outstanding

Weighted average number of common shares outstanding (000s)	Year ended December 31			
Weighted average number of common shares outstanding (0005)	2013	2012		
Weighted average number of common shares	94,694	86,557		
Effect of dilutive elements on common shares ¹	86	151		
Diluted weighted average number of common shares	94,780	86,708		

^{1.} During the year ended December 31, 2013, 2,013,420 of 3,073,684 stock options (1,263,000 of 2,736,684 as at December 31, 2012) and 7,558,684 shares that can be issued on conversion of convertible debentures (7,558,684 as at December 31, 2012) were excluded from the calculation of the diluted weighted average number of shares outstanding as the exercise price was above the average market price of common shares.

As at December 31, 2013, the Corporation had a total of 95,654,911 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 December 31, 2012, it had 93,659,866 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.

As at the date of this MD&A, the Corporation had a total of 95,860,979 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 December 31, 2013, is attributable to the Dividend Reinvestment Plan ("DRIP").

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

LIQUIDITY AND CAPITAL RESOURCES

For the year ended December 31, 2013, the Corporation generated cash flows from operating activities of \$122.3 million, compared with \$60.9 million for the same period last year. During this period, the Corporation used funds from financing activities of \$5.4 million and used funds for investing activities of \$132.2 million, mainly to pay for the construction of three projects that were completed at the end of the year, for pre-construction or construction of five Development Projects and for the Magpie acquisition. The outflows from the financing and investing activities are due mainly to the Corporation's using cash flows from operations and pre-financing its capital expenditure investments in previous quarters. As at December 31, 2013, the Corporation had cash and cash equivalents amounting to \$34.3 million, compared with \$49.5 million as at December 31, 2012.

Cash Flows from Operating Activities

For the year ended December 31, 2013, cash flows generated by operating activities totalled \$122.3 million (\$60.9 million in 2012). This increase is attributable to: a positive net variation in net earnings due mainly to an increase of \$15.1 million in Adjusted EBITDA and a positive net variation of \$10.9 million in the realized loss on derivative financial instruments; a positive net variation of \$2.3 million in distributions from joint ventures; and a positive net variation of \$29.7 million in non-cash operating working capital items.

Cash Flows from Financing Activities

For the year ended December 31, 2013, cash flows used by financing activities totalled \$5.4 million (\$312.9 million generated in 2012). This results mainly from a smaller increase in long-term debt (an increase in long-term debt of \$186.6 million for the year ended December 31, 2013, compared with an increase of \$405.7 million for the same period in 2012) and a \$6.9 million decrease in dividends paid to preferred and common shareholders as well as the issuance of common shares and Series C Preferred Shares in 2012 for net proceeds of \$162.9 million. The total amount of dividends paid to common shareholders decreased as a result of the implementation of the dividend reinvestment plan in August 2012, while the dividends paid to preferred shareholders increased as a result of the issuance of Series C Preferred Shares in December 2012.

Use of Financing Proceeds	Year ended	Year ended December 31			
ose of Financing Froceeus	2013	2012			
		(restated)			
Proceeds from issuance of long-term debt	186,627	405,657			
Net proceeds from issuance of common shares	_	114,571			
Net proceeds from issuance of preferred shares	(353)	48,350			
Proceeds from exercise of share options	_	507			
	186,274	569,085			
Repayment of long-term debt	(145,321)	(201,751)			
Payment of deferred financing costs	(3,066)	(4,248)			
Cash acquired on business acquisition	1,885	_			
Business acquisition	(28,577)	(68,635)			
Restricted cash and short-term investments	38,066	(34,396)			
Loans to related parties	(6,798)	(23,444)			
Net funds withdrawn from (invested into) from the reserves	527	(6,391)			
Additions to property, plant and equipment	(103,680)	(186,760)			
Additions to intangible assets	(27)	(1,929)			
Additions to project development costs	(27,799)	(5,495)			
Investments in joint ventures	(2,923)	(4,225)			
Additions to other long-term assets	(2,962)	(27,892)			
Use of financing proceeds	(280,675)	(565,166)			
(Reduction) increase of working capital	(94,401)	3,919			

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

During the year ended December 31, 2013, the Corporation borrowed \$186.6 million and used \$94.4 million of its working capital to pay for the construction of the Kwoiek Creek and Northwest Stave River projects, the pre-construction and construction of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects and the pre-construction development of the Big Silver Creek and Mesgi'g Ugju's'n projects; acquire the Magpie hydroelectric facility; provide an equity investment to Viger-Denonville, L.P.; repay long-term debt; and reduce drawings under the revolving term credit facility. During the corresponding period of 2012, the Corporation borrowed \$405.7 million and issued \$114.6 million of common shares and \$48.4 million of preferred shares to: pay for the construction of the Kwoiek Creek, Northwest Stave River, Stardale and Gros-Morne II projects; acquire the Brown Lake and Miller Creek facilities and make a deposit to Hydroméga for an acquisition; repay the Glen Miller long-term debt; and contribute \$3.9 million to its working capital.

Cash Flows from Investing Activities

For the year ended December 31, 2013, cash flows used by investing activities amounted to \$132.2 million (\$359.1 million in 2012). During this period, additions to property, plant and equipment accounted for a \$103.7 million outflow (\$186.8 million outflow in 2012), additions to project development costs for a \$27.8 million outflow (\$5.5 million outflow in 2012), the Magpie acquisition for a \$28.6 million outflow (\$68.6 million outflow in 2012 for the acquisition of Brown Lake and Miller Creek), additions to long-term assets for a \$3.0 million outflow (\$27.9 million outflow in 2012) and equity investments in Viger-Denonville, L.P. for a \$2.9 million net outflow (\$4.2 million net outflow in 2012). These items were partly offset by a decrease in restricted cash and short-term investments, which accounted for a \$38.1 million inflow (\$34.4 million outflow in 2012).

Cash and Cash Equivalents

For the year ended December 31, 2013, cash and cash equivalents decreased by \$15.2 million (increased by \$14.6 million in 2012) as a net result of its operating, financing and investing activities. As at December 31, 2013, the Corporation had cash and cash equivalents amounting to \$34.3 million (\$49.5 million as at December 31, 2012).

DIVIDENDS

The following dividends were declared by the Corporation:

	Year ended December 31		
	2013	2012	
Dividends declared on common shares	54,967	50,693	
Dividends declared on common shares (\$ per share)	0.58	0.58	
Dividends declared on Series A Preferred Shares	4,250	4,250	
Dividends declared on Series A Preferred Shares (\$ per share)	1.25	1.25	
Dividends declared on Series C Preferred Shares	3,141	<u> </u>	
Dividends declared on Series C Preferred Shares (\$ per share) ¹	1.570425	_	

^{1.} The initial dividend payment 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 April 15, 2014:

Date of announcement	Record date	Payment date	Dividends per common share (\$)	Dividends per Series A Preferred Share (\$)	Dividends per Series C Preferred Share (\$)
2/25/2014	3/31/2014	4/15/2014	0.1500	0.3125	0.359375

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.

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

FINANCIAL POSITION

At December 31, 2013, the Corporation had \$2,377 million in total assets, \$1,711 million in total liabilities, including \$1,340 million in long-term debt and \$665.9 million in shareholders' equity.

Also at December 31, 2013, the Corporation had a working capital ratio of 1.18:1.00 (1.58:1.00 as at December 31, 2012). In addition to cash and cash equivalents amounting to \$34.3 million, the Corporation had restricted cash and short-term investments of \$49.7 million and reserve accounts of \$47.6 million at the end of the year.

Assets

As at December 31, 2013, the Corporation had \$2,377 million in total assets (\$2,296 million as at December 31, 2012).

Highlights of significant variations in total assets during 2013

- A net decrease in cash and cash equivalents and restricted cash and short-term investments from \$137.3 million as at December 31, 2012, to \$84.0 million as at December 31, 2013, due mainly to amounts being drawn as construction progressed on the Kwoiek Creek project, while the funds were received in full in 2012 upon closing of the financing for this project, partly offset by the addition of, and drawings on, the Northwest Stave River loan;
- A decrease in accounts receivable from \$50.1 million to \$19.8 million, as explained in the "Working Capital Items" section below;
- A decrease in loans to related parties of \$16.6 million due mainly to the completion of a \$23.4 million distribution by the Harrison Operating Facilities and a similar distribution of \$6.8 million initiated in the fourth quarter of 2013;
- An increase in property, plant and equipment from \$1,427 million to \$1,583 million, due mainly to the transfer of Development Projects under construction from project development costs, and the acquisition of the Magpie hydroelectric facility, partly offset by depreciation;
- An increase in intangible assets from \$429.4 million to \$466.1 million, due mainly to the acquisition of the Magpie hydroelectric facility, partly offset by amortization;
- A decrease in project development costs from \$103.5 million to \$81.6 million, due mainly to the transfer of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects to property, plant and equipment or intangible assets upon the start of construction activities, partly offset by pre-construction activities related to the Big Silver Creek and Mesgi'g Ugiu's'n projects.

Working Capital Items

As at December 31, 2013, working capital was positive at \$19.1 million with a working capital ratio of 1.18:1.00. As at December 31, 2012, working capital was positive at \$80.9 million with a working capital ratio of 1.58:1.00. The decrease in the working capital ratio over this period is due to decreases in restricted cash and short-term investments, in accounts receivable and in loans to related parties and to an increase in accounts payable, which are explained separately below. These items were partly offset by the reclassification of the Carleton loan into long-term debt following its refinancing in June 2013; since November 2012, the entire amount of the loan had been recorded in the current portion of long-term debt in view of its then November 2013 term maturity.

In view of these ratios, 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 December 31, 2013, the Corporation had drawn US\$13.9 million and \$170.5 million as cash advances while \$30.3 million had been used for issuing letters of credit.

Restricted cash and short-term investments: are related to the Harrison Operating Facilities, the Kwoiek Creek loan and the Northwest Stave River Ioan. As at December 31, 2013, restricted cash and short-term investments amounted to \$49.7 million, of which \$6.7 million was related to the Harrison Operating Facilities, \$31.5 million to the Kwoiek Creek Ioan and \$11.6 million to the Northwest Stave River Ioan (\$87.8 million as at December 31, 2012, of which \$6.6 million was related to the Harrison Operating Facilities and \$81.2 million to the Kwoiek Creek Ioan). The decrease stems mainly from amounts being drawn as construction progressed on the Kwoiek Creek project, partly offset by the addition of the Northwest Stave River Ioan.

Accounts receivable: decreased from \$50.1 million as at December 31, 2012, to \$19.8 million as at December 31, 2013. The decrease stems mainly from the collection of \$8.6 million in commodity taxes receivable and \$15.3 million from Hydro-Québec for the Gros-Morne substation and from a \$3.7 million decrease in trades receivable.

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

Loans to related parties: decreased from \$23.4 million as at December 31, 2012, to \$6.8 million as at December 31, 2013, as the Harrison Operating Facilities completed a distribution that resulted in a \$23.4 million decrease in loans to related parties, as well as a corresponding decrease in non-controlling interests with no impact on net earnings or cash flows. During the fourth quarter, the Harrison Operating Facilities initiated another distribution that resulted in a \$6.8 million increase in loans to related parties and a corresponding decrease in cash, representing a cash outflow in the same amount. The loans were reimbursed on January 1, 2014, when the distribution was declared.

Accounts payable and other payables: increased from \$41.3 million as at December 31, 2012, to \$48.3 million as at December 31, 2013, due mainly to accounts payable related to the construction of the Kwoiek Creek and Northwest Stave River facilities.

Derivative financial instruments included in current liabilities: decreased from \$17.2 million as at December 31, 2012, to \$12.9 million as at December 31, 2013, due mainly to the settlement of the Northwest Stave River bond forward contracts.

Current portion of long-term debt: relates to the payments to be made within a year on the Operating Facilities' term loans and bonds. The decrease from \$63.9 million as at December 31, 2012, to \$26.6 million as at December 31, 2013, is due mainly to the refinancing of the Carleton loan in June 2013 and the reclassification of the outstanding balance of the loan as long-term debt.

Reserve Accounts

	December 31, 2013	December 31, 2012	
		(restated)	
Hydrology/wind reserve	43,972	45,291	
Major maintenance reserve	3,590	2,325	
Total	47,562	47,616	

The Corporation holds two types of reserve accounts designed to help ensure its stability:

- i) The Hydrology/wind reserve is established at the start of commercial operations at a facility to compensate for the variability of cash flows related to fluctuations in hydrology and the wind regime and to other unpredictable events. The amounts in this reserve are expected to vary from quarter to quarter according to the seasonality of cash flows.
- ii) The Major maintenance reserve is established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity.

The availability of funds in the Hydrology/wind and Major maintenance reserve accounts may be restricted by credit agreements and trust indentures.

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. They are depreciated using the straight-line method over the lesser of (i) the period for which the Corporation owns the rights to the assets or (ii) a period of 15 to 75 years for hydroelectric facilities or 15 to 25 years for wind farms or 25 years for the solar farm. The Corporation had \$1,583 million in property, plant and equipment as at December 31, 2013, compared with \$1,427 million as at December 31, 2012. This increase stems mainly from the acquisition of the Magpie hydroelectric facility, the construction of the Kwoiek Creek and Northwest Stave River hydroelectric facilities and the transfer of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects currently under construction, partly offset by depreciation.

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

Intangible Assets

Intangible assets consist of various PPAs, permits and licenses. They also include the extended warranty for the Montagne Sèche and Gros-Morne wind farm turbines. The Corporation reported \$466.1 million in intangible assets as at December 31, 2013, an increase of \$36.7 million from the \$429.4 million reported as at December 31, 2012. This increase stems from the addition of \$30.4 million in intangible assets from the Magpie acquisition and of \$14.7 million in intangible assets from the subsequent adjustment of the Brown Lake and Miller Creek acquisitions, partly offset by amortization.

In addition, the Corporation has changed the accounting estimates to amortize intangible assets of the Quebec hydroelectric facilities to reflect the renewal rights of their PPAs for periods of 20 to 25 years. For more information on changes to accounting policies used, please refer to the "Accounting Changes" section.

Excluding \$4.4 million related to the wind farms' extended warranty, intangible assets are amortized using the straight-line method over four- to 69-year periods that commence when the related project is commissioned or acquired. The wind farms' extended warranty is amortized using the straight-line method over the three-year extended warranty period.

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. As at December 31, 2013, the Corporation had \$81.6 million in project development costs (\$103.5 million as at December 31, 2012). This decrease is due to the transfer of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects to property, plant and equipment or intangible assets upon the start of construction activities, partly offset by expenses incurred for the Big Silver Creek and Mesgi'g Ugju's'n Development Projects.

Investments in Joint Ventures

Investments in joint ventures represent the Corporation's ownership portion of joint ventures, which are accounted for using the equity method. As at December 31, 2013, the Corporation had \$24.6 million in investments in joint ventures (\$18.9 million as at December 31, 2012). This \$5.7 million increase reflects the recognition of net earnings at the joint venture level during the year and a \$2.9 million net equity investment in Viger-Denonville, L.P.

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 \$487.3 million as at December 31, 2013. In addition, Umbata Falls, L.P. had swap contracts totaling \$46.7 million to hedge all of the Umbata Falls loan and Viger-Denonville, L.P. had a swap contract of \$58.5 million to hedge 95% of the Viger-Denonville loan. Consequently, as at December 31, 2013, interest rate swaps related to outstanding debts combined with the \$819.7 million in existing fixed-rate debts and the \$79.8 million in convertible debentures mean that 98% 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 totaling \$405.0 million (\$340.0 million as at December 31, 2013) for the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek 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 December 31, 2013, derivatives that will be settled upon closing of financing had a positive market value of \$6.0 million.

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

Outstanding Derivative Financial Instruments	Maturity	Early termination option	December 31, 2013	December 31, 2012
				(restated)
Bond forwards, from 3.04% to 3.27% (1.93% to 2.38% in 2012)	2014	None	340,000	40,000
Interest rate swaps, from 3.96% to 4.09%	2015	None	15,000	15,000
Interest rate swap, 4.27%	2016	None	3,000	3,000
Interest rate swaps, 4.27% to 4.41%	2018	None	82,600	82,600
Interest rate swaps, 2.94% to 4.83%, amortizing	2026	None	52,539	43,514
Interest rate swaps, from 3.35% to 3.60%, amortizing	2027	None	39,807	42,792
Interest rate swap, 3.74%, amortizing	2030	None	97,723	101,780
Interest rate swap, 4.22%, amortizing	2030	2016	28,803	30,021
Interest rate swap, 4.25%, amortizing	2031	2016	45,417	47,323
Interest rate swap, 4.61%, amortizing	2035	2025	102,818	105,031
Interest rate swap, 2.85%, amortizing	2041	2016	19,591	19,853
			827,298	530,914

Derivatives had a net negative value of \$31.0 million at December 31, 2013 (negative \$78.0 million at December 31, 2012). This favourable difference is due mainly to an increase in benchmark interest rates since the end of 2012. The estimated impact of a 0.1% interest rate increase would decrease the interest rate derivatives-related liability by \$10.3 million. Conversely, a 0.1% interest-rate decrease would increase the interest rate derivatives-related liability by \$10.5 million. These figures exclude the impact of derivatives used to hedge loans of the Corporation's joint ventures. For information on the impact of derivatives used in the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Some interest rate swaps have embedded early termination options that are exercisable only on their underlying debt's maturity date. The triggering of these options could pose a liquidity risk. Should the early termination option be triggered, a presumed realized loss would be offset by the savings realized on future interest expenses, as a negative swap value would be the result of an environment in which interest rates were lower than the rate embedded in the swap.

The Corporation has recorded Derivatives using an estimated credit-adjusted mark-to-market valuation that is determined by increasing the swap-based discount rates used to calculate the estimated mark-to-market valuation by an estimated credit spread for the relevant term and counterparty for each Derivative. In the case of Derivatives that Innergex accounts for as assets (i.e. Derivatives for which the counterparties owe Innergex), the credit spread for the bank counterparty was added to the swap-based discount rate to determine the estimated credit-adjusted value, whereas, in the case of Derivatives accounted for as liabilities (i.e. Derivatives for which Innergex owes the counterparties), Innergex's credit spread was added to the swap-based discount rate. As at December 31, 2013, all bond forward contracts and interest rate swaps were accounted for as liabilities and credit spreads from 0.33% to 2.21% were added to the discount rates. Most bond forwards were accounted for as assets. No credit spreads were added to them. The estimated credit-adjusted values of the Derivatives are subject to changes in credit spreads of Innergex and its counterparties.

As at December 31, 2013, the fair market value of the derivative financial instruments related to some PPAs with Hydro-Québec was positive at \$6.6 million (\$8.4 million as at December 31, 2012). These instruments represent the value attributed to minimum inflation clauses of 3% per year included in these PPAs.

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 or for which construction has been completed but costs remained to be paid. As at December 31, 2013, the Corporation had \$9.9 million in accrual for acquisition of long-term assets (\$12.9 million as at December 31, 2012). This decrease stems mainly from payments made in relation to the Northwest Stave River project, partly offset by development and construction costs incurred for the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek projects.

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

Long-Term Debt

As at December 31, 2013, long-term debt totalled \$1,340 million (\$1,231 million as at December 31, 2012). The \$109.7 million increase in long-term debt results mainly from the addition of the \$72.0 million financing for the Northwest Stave River hydroelectric project, higher proceeds of \$11.6 million from the refinancing of the Carleton wind farm and the addition of the Magpie debts in the amount of \$66.0 million, which were offset by a \$19.3 million net decrease in drawings under the revolving term credit facility and \$26.5 million in scheduled long-term debt repayments. The Magpie debts consist of \$57.7 million in project financing, a \$5.5 million convertible debenture and a \$1.4 million non-interest bearing debenture repayable over the next five years. These debt amounts reflect their adjustment to fair market value upon consolidation of Magpie.

Outstanding Lawrence Dalet	Effective all-in	Year ended December			December 31
Outstanding Long-term Debt	interest rate	Maturity	Note	2013	2012
					(restated)
Prime rate advances		2018		20	20
Bankers' acceptances		2018		170,480	189,780
LIBOR advances, US\$13,900		2018		14,784	13,829
Revolving term credit facility	5.29%		i)	185,284	203,629
Term loans					
Fitzsimmons Creek, floating rate	4.10%	2016	ii)	21,791	22,133
Hydro-Windsor, fixed rate	8.25%	2016	iii)	3,186	4,145
Montagne-Sèche, floating rate	6.72%	2016	iv)	28,803	30,021
Magpie, fixed rate	2.33%	2017	v)	1,156	_
Magpie, non-interest bearing	5.30%	2017	vi)	1,399	_
Rutherford Creek, fixed rate	6.88%	2024	vii)	45,757	48,634
Ashlu Creek, floating rate	6.14%	2025	viii)	98,822	100,810
Magpie, fixed rate	6.16%	2025	ix)	5,497	_
L'Anse-à-Valleau, floating rate	5.93%	2026	x)	41,188	43,515
Carleton, floating rate	5.41%	2027	xi)	51,712	43,412
Stardale, floating rate	5.79%	2030	xii)	106,220	110,630
Magpie, fixed rate	4.37%	2031	xiii)	56,566	_
Kwoiek Creek, fixed rate subordinated term loan	14.00%	2054	xiv)	3,662	150
Kwoiek Creek, fixed rate	5.08%	2053	xv)	168,500	168,500
Northwest Stave River, fixed rate	5.30%	2053	xvi)	71,972	_
Other loans with various maturities and interest		2014-2017		116	222
rates		2014-2017		110	222
Bonds					
Harrison Operating Facilities, real return	3.97%	2049	xvii)	223,049	225,137
Harrison Operating Facilities, fixed rate	6.61%	2049	xviii)	211,681	213,738
Harrison Operating Facilities, real return	5.04%	2049	xix)	27,031	26,760
Deferred financing costs				(13,025)	(10,728)
Project-level debt				1,155,083	1,027,079
Total long-term debt				1,340,367	1,230,708
Current portion of long-term debt				(26,649)	(63,926)
Long-term portion of long-term debt				1,313,718	1,166,782

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

Explanatory notes:

- i) a \$425.0 million **revolving credit term facility** secured by a first-ranking hypothec on some Innergex assets and by various security interests granted by some of its subsidiaries. The facility will mature in 2018 and is not amortized. Advances are made in the form of bankers' acceptances ("BA"), prime-rate advances, U.S. base-rate advances, LIBOR advances or letters of credit. In all cases, interest is calculated at the prevailing benchmark rate plus an additional margin based on Innergex's ratio of adjusted consolidated senior debt to adjusted EBITDA. As at December 31, 2013, \$185.3 million was due under this facility and \$30.3 million was used for the issuance of letters of credit; thus the unused and available portion of the revolving credit term facility totalled \$209.4 million. The carrying value of assets of the Corporation and subsidiaries given as securities under this facility total approximately \$694.5 million. As at December 31, 2013, the all-in interest rate was 5.29% after accounting for the interest rate swaps;
- ii) a five-year non-recourse term loan maturing in 2016 and secured by the **Fitzsimmons Creek** hydroelectric facility. The loan's monthly principal payments are variable, based on a 30-year amortization period, and are set to \$278 for 2014. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2013, the all-in effective interest rate was 4.10% after accounting for the interest rate swap;
- iii) a 20-year non-recourse term loan maturing in 2016 and secured by the **Hydro-Windsor** hydroelectric facility. The loan is repayable by monthly blended payments of principal and interest totalling \$105. The principal payments are set to \$960 for 2014. The loan bears interest at an effective fixed interest rate of 8.25%;
- iv) a four-year non-recourse term loan maturing in 2016 and secured by the Corporation's 38% interest in the **Montagne Sèche** wind farm. The loan's quarterly principal payments began on March 31, 2012; they are variable, based on an 18.5-year amortization period, and set to \$1.3 million for 2014. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2013, the all-in effective interest rate was 6.72% after accounting for the interest rate swap;
- v) a \$1.2 million bridge loan maturing in 2017 assumed as part of the acquisition of the **Magpie** hydroelectric facility. The loan is repayable in monthly blended payments of principal and interest totaling \$27. The principal payments are set to \$271 for 2014. The loan was accounted for at its fair market value of \$1.3 million on the date of the Magpie acquisition and bears interest at an effective fixed interest rate of 2.33%:
- vi) a \$2.0 million debenture maturing on December 31, 2017 assumed as part of the acquisition of the **Magpie** hydroelectric facility, bearing no interest and repayable in annual installments of \$400. The debenture was accounted for at its fair market value of \$1.8 million on the date of the Magpie acquisition and bears interest at an effective rate of 5.30%;
- vii) a 20-year non-recourse term loan maturing in 2024 and secured by the **Rutherford Creek** hydroelectric facility. The loan's monthly blended payments of principal and interest totalling \$511 began on July 1, 2012. The principal payments are set to \$3.1 million for 2014. The loan bears interest at a fixed rate of 6.88%;
- viii) a 15-year non-recourse term loan maturing in 2025 and secured by the **Ashlu Creek** hydroelectric facility. The loan's quarterly principal payments are variable, based on a 25-year amortization period, and set to \$2.4 million for 2014. The loan bears interest at the BA rate or prime-rate plus an applicable credit margin. As at December 31, 2013, the all-in effective interest rate was 6.14% after accounting for the interest rate swaps;
- ix) a \$3.0 million convertible debenture maturing in 2025 assumed as part of the acquisition of the **Magpie** hydroelectric facility. The convertible debenture was accounted for at its fair market value of \$5.5 million on the date of the Magpie acquisition for an effective rate of 6.16%. It entitles the Minganie Regional County Municipality to a 30% interest in the facility upon conversion of the debenture on or before January 1, 2025;
- x) a 18.5-year non-recourse term loan maturing in 2026 and secured by the Corporation's 38% interest in the **L'Anse-à-Valleau** wind farm. The loan's quarterly principal payments are variable, based on an 18.5-year amortization period, and set to \$2.5 million for 2014. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2013, the all-in interest rate was 5.93% after accounting for the interest rate swap;
- xi) a 14-year non-recourse term loan secured on June 26, 2013 and maturing in 2027, to refinance the Corporation's 38% interest in the **Carleton** wind farm. The loan's quarterly principal payments are variable, based on a 14-year amortization period starting on June 26, 2013, and set to \$2.7 million for 2014. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2013, the all-in effective interest rate was 5.41% after accounting for the interest rate swaps;

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

- xii) an 18-year non-recourse term loan maturing in 2030 and secured by the **Stardale** solar farm. The loan's quarterly principal payments are variable based on an 18-year amortization period and set to \$4.6 million for 2014. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2013, the all-in effective interest rate was 5.79%;
- xiii) a \$49.3 million non-recourse term loan maturing in 2031 assumed as part of the acquisition of the **Magpie** hydroelectric facility. The loan is repayable in monthly blended payments of principal and interest totalling \$379. The principal payments are set to \$1.5 million for 2014. It was accounted for at its fair market value of \$57.4 million on the date of the Magpie acquisition and bears interest at an effective fixed interest rate of 4.37%;
- xiv) a subordinated non-recourse term loan made by the Corporation's partner to Kwoiek Creek Resources Limited Partnership ("KCRLP"), the owner of the **Kwoiek Creek** hydroelectric project. As per the agreements related to the project, both partners can participate in the financing of the project. The Corporation's subordinated non-recourse term loan made to KCRLP, which was eliminated in the financial statement consolidation process, amounted to \$55.5 million as at December 31, 2013. These loans bear interest at a rate of 14.0%;
- xv) a \$168.5 million non-recourse construction and term project financing for the Kwoiek Creek hydroelectric project, of which \$154.0 million had been used as at December 31, 2013, to pay for project costs while the difference is held in restricted cash to pay for future costs. The loan bears a fixed interest rate of 5.08%. It will convert into a 39-year term loan following the start of the project's commercial operation and will be amortized over a 36-year period three years later;
- xvi) a \$72.0 million non-recourse construction and term project financing for the **Northwest Stave River** hydroelectric project, of which \$67.5 million had been used as at December 31, 2013, to pay for project costs while the difference is held in restricted cash to pay for future costs. The loan bears a fixed interest rate of 5.30%. It will convert into a 40-year term loan following the start of the project's commercial operation and will be amortized over a 35-year period starting in the sixth year;
- xvii) a senior real return bond maturing in 2049 secured by the **Harrison Operating Facilities**. The bond is repayable by semi-annual blended payments of principal and interest totalling \$5.8 million before CPI adjustment (\$6.4 million including CPI adjustment in 2013). On December 1, 2031, the payment amount decreases to \$4.5 million before CPI adjustment. The principal payments are set to \$5.2 million including CPI adjustment for 2014. The bond bears interest at a fixed rate adjusted by an inflation ratio and an inflation compensation interest factor. Both inflation adjustments are based on the non-seasonally adjusted CPI. As at December 31, 2013, the all-in effective interest rate was 3.97%;
- xviii)a senior fixed bond maturing in 2049 secured by the **Harrison Operating Facilities**. The bond is repayable by semi-annual blended payments of principal and interest totalling \$8.1 million. On September 1, 2031, the payment amount decreases to \$6.7 million. The principal payments are set to \$2.9 million for 2014. The bond bears interest at an effective fixed interest rate of 6.61%;
- xix) a junior real return bond maturing in 2049 secured by the **Harrison Operating Facilities** but second ranking to the bonds described in xvii) and xviii). Quarterly interest payments amount to \$291 before CPI adjustment (\$321 including CPI adjustment in 2013). Principal payments do not commence until June 1, 2017, on which date the quarterly blended payments of principal and interest will amount to \$389 before CPI. The bond bears interest at a fixed rate adjusted by an inflation ratio and an inflation compensation interest factor. Both inflation adjustments are based on the non-seasonally adjusted CPI. As at December 31, 2013, the all-in effective interest rate was 5.04%.

Since the beginning of the 2013 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. If they are not met, certain financial and non-financial covenants included in the credit agreements, trust indentures or PPAs 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.

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

Convertible Debentures

On March 16, 2010, the Corporation completed the issuance of Convertible Debentures for a total notional amount of \$80.5 million. As at December 31, 2013, the debt portion of the Convertible Debentures was \$79.8 million and the equity portion was \$1.3 million (\$79.7 million and \$1.3 million respectively as at December 31, 2012).

The Convertible Debentures bear interest at an annual rate of 5.75% and will mature on April 30, 2017. Each Convertible Debenture is convertible into common shares of the Corporation at the option of the holder at any time prior to the earlier of April 30, 2017, and the redemption date specified by the Corporation. The conversion price is \$10.65 per common share, being a conversion rate of approximately 93.8967 common shares per thousand dollars of principal amount of convertible debentures. Holders converting their Convertible Debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their Convertible Debentures to the date of conversion.

For more information about the issuance of the Convertible Debentures, please refer to the *Short Form Prospectus* dated February 25, 2010, available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

The Convertible Debentures are subordinated to all other indebtedness of the Corporation.

Other Liabilities

Other liabilities, including amounts shown in current liabilities, consist of contingent considerations and asset retirement obligations relating to the Corporation's wind and solar farms. As at December 31, 2013, the Corporation had \$10.9 million in other liabilities (\$8.9 million as at December 31, 2012). This \$2.1 million increase is due mainly to the addition of a contingent consideration to the Minganie Regional County Municipality until the convertible debenture issued by Magpie L.P. is converted. Upon conversion, the Minganie Regional County Municipality will be entitled to a participation of 30% in Magpie L.P.

Deferred Income Taxes

The tax impact of temporary differences may result in future tax assets or liabilities. As at December 31, 2013, the Corporation's net deferred tax liability was \$161.9 million (\$133.4 million as at December 31, 2012).

Shareholders' Equity

As at December 31, 2013, the shareholders' equity of the Corporation totalled \$665.9 million, including \$81.4 million of non-controlling interests, compared with \$687.9 million, including \$107.6 million of non-controlling interests as at December 31, 2012. The decrease in total shareholders' equity stems mainly from the \$23.4 million decrease in non-controlling interests following the distribution made by the Harrison Operating Facilities, partly offset by an increase of \$18.1 million resulting from the issuance of 2.0 million common shares through the Corporation's DRIP. Furthermore, the increase in shareholders' equity resulting from the recognition of net earnings of \$45.4 million was offset by a decrease resulting from dividends declared on preferred and common shares of \$62.4 million.

Special resolutions were adopted on May 14, 2013 to approve the reduction of the legal stated capital account maintained in respect of the common shares of the Corporation, without any payment or distribution to the shareholders. This resulted in a decrease of \$128.2 million of the shareholders' capital account and a corresponding increase of \$128.2 million of the contributed surplus from reduction of capital on common shares account.

Preferred Shares

On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at \$25.00 per share for aggregate gross proceeds of \$85.0 million. For the initial five-year period up to but excluding January 15, 2016, the holders of Series A Preferred Shares are entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board of Directors. The dividends are payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to \$1.25 per share.

The Series A Preferred Shares are rated P-3 by S&P and Pfd-4 (high) by DBRS (unsolicited rating).

For more information about the Series A Preferred Shares, please refer to the *Short Form Prospectus* dated September 7, 2010 available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

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

On December 11, 2012, the Corporation issued a total of 2,000,000 Cumulative Redeemable Fixed-Rate Preferred Shares Series C at \$25.00 per share for aggregate gross proceeds of \$50.0 million. Holders of the Series C Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to \$1.4375 per share.

The Series C Preferred Shares will not be redeemable by the Corporation prior to January 15, 2018. They do not have a fixed maturity date and are not redeemable at the option of the holders.

The Series C Preferred Shares are rated P-3 by S&P and Pfd-4 (high) by DBRS (unsolicited rating).

For more information about the Series C Preferred Shares, please refer to the *Short Form Prospectus* dated December 4, 2012, available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

Off-Balance-Sheet Arrangements

As at December 31, 2013, the Corporation had issued letters of credit totaling \$42.7 million to meet its obligations under its various PPAs and other agreements. Of this amount, \$30.3 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 \$12.2 million in corporate guarantees to support the construction of the Gros-Morne wind farm and the performance of the Brown Lake hydroelectric facility.

Contractual Obligations

As at December 31, 2013	Total	Under 1 year	1 to 3 years	4 to 5 years	Thereafter
Long-term debt including convertible debentures	1,486,242	28,061	104,740	330,360	1,023,081
Interest on long-term debt and convertible debentures	1,042,688	69,988	133,477	117,260	721,963
Others	19,316	1,801	3,123	2,469	11,923
Purchase (Contractual) obligations ¹	140,347	48,440	46,300	3,888	41,719
Total contractual obligations	2,688,593	148,290	287,640	453,977	1,798,686

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

Contingencies

An acquisition realized in 2011 provides for the potential payment of additional amounts to the vendors over a period commencing on the acquisition date and ending on the 40th anniversary of the last project under development to achieve commercial operation (or to April 4, 2061 if earlier). The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. The maximum aggregate amount of all deferred payments under this acquisition is limited to a present value amount of \$35.0 million as at the acquisition date.

In connection with another acquisition, the Corporation agreed to pay contingent considerations based upon future events for a period of three years after April 20, 2011. These contingent considerations provide for the sharing of the potential value created if the project benefits from a better return than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. No maximum applies to the potential sharing.

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

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

FREE CASH FLOW AND PAYOUT RATIO

Free Cash Flow

When evaluating its operating results, a key performance indicator for the Corporation is the cash 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 year the Free Cash Flow is generated. The Corporation 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 adjustments include adding back transaction costs related to realized acquisitions (which are financed at the time of the acquisition), adding back a cash receipt by the Harrison Operating Facilities for the wheeling services to be provided to the Northwest Stave River facility, 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	Year	Year ended December 31			
Free Casii Flow allu Fayout Ratio Calculation	2013	2012	2011		
		(restated)	(restated)		
Cash flows from operating activities	122,286	60,907	43,278		
(Subtract) Add the following items:					
Changes in non-cash operating working capital items	(30,283)	(601)	23,921		
Maintenance capital expenditures net of proceeds from disposals	(2,441)	(2,788)	(3,097)		
Scheduled debt principal payments	(26,520)	(19,996)	(14,512)		
Free Cash Flow attributed to non-controlling interests ¹	(5,453)	(5,666)	(8,179)		
Dividends declared on Preferred shares	(7,391)	(4,250)	(4,250)		
Adjust for the following elements:					
Transaction costs related to realized acquisitions	609	2,164	1,863		
Realized losses (gains) on derivative financial instruments	3,259	14,127	_		
Other elements	4,916 ²	_			
Free Cash Flow	58,982	43,897	39,024		
Dividends declared on common shares	54,967	50,693	43,990		
Payout Ratio - before the impact of the DRIP	93%	115%	113%		
Dividends declared on common shares excluding shares under the DRIP ³	36,892	47,758	43,990		
Payout Ratio - after the impact of the DRIP	63%	109%	113%		

^{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 year they are generated.

For the year ended December 31, 2013, the Corporation generated Free Cash Flow of \$59.0 million, compared with \$43.9 million for the same period last year. This increase is due mainly to greater cash flows from operations resulting from the increase in the number of facilities in operation, partly offset by greater scheduled debt principal payments resulting from the start of the amortization period on a number of project-level debts (Rutherford Creek, Stardale, Montagne Sèche) as well as higher dividends paid on preferred shares following the issuance of Series C Preferred Shares in December 2012.

^{2.} The \$4.9 million represents a cash receipt by the Harrison Operating Facilities for the wheeling services to be provided to the Northwest Stave River facility, a portion of which was attributed to non-controlling interests.

^{3.} Represents dividends declared on all common shares outstanding at the time of the declaration, net of shares registered in the DRIP that would not actually result in a cash outflow. The DRIP was implemented on August 31, 2012.

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

Payout Ratio

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

For the year ended December 31, 2013, the Corporation declared dividends of \$0.58 per common share, the same as in 2012. These dividends corresponded to 93% of Free Cash Flow, compared with 115% for the same period last year. The improvement is due mainly to the greater Free Cash Flow generated as explained above.

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.

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

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.

PROJECTED FINANCIAL PERFORMANCE

As at the date of this MD&A, the Corporation has 32 Operating Facilities with a net installed capacity of 672 MW (gross 1,164 MW) and annualized consolidated long-term average production of 2,883 GWh. The Corporation is also pursuing the development of five Development Projects with power purchase agreements.

Outlook for 2014

	2014	2013	2012
Power Generated (GWh)	approx. +20%	2,382 +13%	2,105 +13%
Revenues	approx. +20%	198,259 +12%	176,655 +22%
Adjusted EBITDA	approx. +20%	148,916 +11%	133,792 +24%
Number of facilities in operation ¹	32	32	28
Net installed capacity ¹ (MW)	672	672	577
Consolidated LTA production, annualized ¹ (GWh)	2,883	2,883	2,407

^{1.} Figures for 2013 include the Northwest Stave River and Kwoiek Creek hydroelectric facilities that were completed on time and on budget in December 2013 and were commissioned effective December 18, 2013 and January 1, 2014, respectively.

Outlook for 2017

The Corporation makes certain projections to provide readers with an indication of its business activities and operating performance once the five existing Development Projects have been commissioned. Please refer to the "Development Projects" section for more information on these projects. These projections do not take into account possible acquisitions, divestments or additional Development Projects following the award of any new power purchase agreements.

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

Projected Installed Capacity

The Corporation believes that installed capacity provides a good indication of the size and magnitude of its operations. Once the five existing Development Projects have been commissioned, the Corporation expects its net installed capacity to increase from 672 MW (gross 1,164 MW) at the date of this MD&A to 882 MW (gross 1,484 MW) at the end of 2016, corresponding to a 31% increase (gross 27%). Net installed capacity reflects the fact that some of the Corporation's Operating Facilities are not wholly-owned. Installed capacity includes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method.

Projected Long-Term Average Production (LTA)

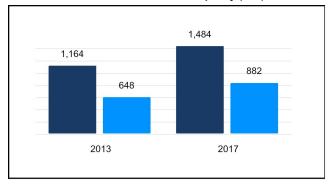
A key performance indicator for the Corporation is to compare actual electricity generation with the expected LTA production for each facility. Once the five existing Development Projects have been commissioned, the Corporation expects its annualized consolidated LTA production to increase from 2,883 GWh at the date of this MD&A to 4,047 GWh starting in 2017, corresponding to a 40% increase. Consolidated LTA production is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method.

Projected Adjusted EBITDA

A key performance indicator for the Corporation is Adjusted EBITDA generation. Once the five Development Projects have been commissioned, the Corporation expects to generate annualized Adjusted EBITDA starting in 2017 of approximately \$285.0 million (adjusted for an inflation component thereafter), compared with \$148.9 million in 2013. This represents an annual compound growth rate of approximately 18% for the 2013-2017 period. Adjusted EBITDA is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method. The annual Adjusted EBITDA for these facilities combined attributable to the Corporation is approximately \$8.0 million.

It should be noted that Adjusted EBITDA does not take into account the impact of interest and principal payments on the Corporation's existing debt and on the project-level debt financing it expects to put in place to finance the construction of its five Development Projects.

Gross and Net Installed Capacity (MW)



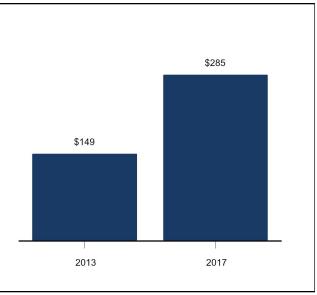
2013 figures include Kwoiek Creek and Northwest Stave River

Annualized Consolidated LTA Production

	As at the date of this MD&A	Starting in 2017
Hydro	2,168.4	2,817.0
Wind	676.5	1,192.0
Solar ¹	38.4	37.6
Total	2,883.3	4,046.6

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

Adjusted EBITDA (\$M)



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

SEGMENT INFORMATION

Geographic Segments

As at December 31, 2013, the Corporation had interests in 23 hydroelectric facilities (including Northwest Stave River and excluding Kwoiek Creek), six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2013, revenues generated by the Horseshoe Bend hydroelectric facility in the United States totalled \$3.0 million (\$3.4 million in 2012), representing a 1.5% contribution (1.9% in 2012) to the Corporation's consolidated revenues for these periods. The decrease is due mainly to below-average water flows in 2013, compared with above-average water flows last year.

Operating Segments

As at December 31, 2013, 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.

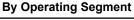
Year ended December 31, 2013	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	1,655,371	686,380	40,069		2,381,820
Revenues	126,932	54,499	16,828	_	198,259
Expenses:					
Operating expenses	22,849	9,939	1,159	_	33,947
General and administrative expenses	7,373	2,140	317	1,364	11,194
Prospective project expenses	_	_	_	4,202	4,202
Adjusted EBITDA	96,710	42,420	15,352	(5,566)	148,916
Year ended December 31, 2012 (restated)					
Power generated (MWh)	1,529,276	542,295	33,374	_	2,104,945
Revenues	119,421	45,558	11,676	_	176,655
Expenses:					
Operating expenses	20,357	7,960	533	_	28,850
General and administrative expenses	5,314	2,248	278	1,761	9,601
Prospective project expenses	_	_	_	4,412	4,412
Adjusted EBITDA	93,750	35,350	10,865	(6,173)	133,792

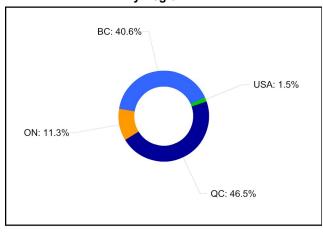
(in thousands of Canadian dollars, except as noted, and amounts per share)

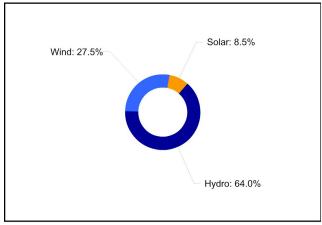
As at December 31, 2013	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	_	_	_	8,269
Total assets	1,449,527	387,062	128,146	412,339	2,377,074
Total liabilities	949,570	240,372	116,085	405,112	1,711,139
Acquisition of property, plant and equipment during the year	66,581	1,213	100	89,501	157,395
As at December 31, 2012 (restated)					
Goodwill	8,269	_	_	_	8,269
Total assets	1,293,971	423,634	139,222	439,613	2,296,440
Total liabilities	807,661	290,913	127,393	382,541	1,608,508
Acquisition of property, plant and equipment during the year	64,936	2,709	129	169,508	237,282

Breakdown of 2013 Revenues

By Region







Hydroelectric Generation Segment

For the year ended December 31, 2013, this segment produced 93% of the LTA and generated revenues of \$126.9 million (compared with production at 98% of the LTA and revenues of \$119.4 million in 2012). In Ontario and Quebec, water flows have remained better than average at most facilities since the beginning of the year. In British Columbia, above-average water flows at most facilities in the second and third quarter could not compensate for below-average hydrology in the first and fourth quarters, as this province had one of the driest years on record, with precipitations approximately 30% below average. Production levels were also affected by a shutdown for capital improvements at the Miller Creek facility between August 8 and November 13. In the United States, water flows remained below average throughout the year, except for the second quarter. The 6% increase in revenues stems mainly from the full-year contribution of the Brown Lake and Miller Creek facilities acquired in October 2012 and the acquisition of the Mapgie facility in July 2013.

The increase in total assets since December 31, 2012, is attributable mainly to the increase in property, plant and equipment relating to the transfer of the Northwest Stave River facility from the Site Development segment and the acquisition of the Magpie facility, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2012, is attributable mainly to the addition of the Northwest Stave River loan and the acquisition of Magpie, offset by scheduled repayment of long-term debt and the decrease in derivative financial instruments.

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

Wind Power Generation Segment

For the year ended December 31, 2013, this segment produced 101% of the LTA and generated revenues of \$54.5 million (compared with production at 95% of the LTA and revenues of \$45.6 million in 2012). Above-average wind conditions during the third quarter were enough to offset the lower-than-average wind conditions during the first, second and fourth quarters. The 20% increase in revenues is due mainly to the higher-than-average production levels and the additional capacity at the Gros-Morne wind farm since November 2012.

The decrease in total assets since December 31, 2012, is attributable mainly to depreciation of property, plant and equipment and amortization of intangible assets.

The decrease in total liabilities since December 31, 2012, is attributable mainly to payments of accounts payable related to Gros-Morne and Montagne Sèche and to scheduled repayment of long-term debt, which have offset the additional proceeds of \$11.6 million from the refinancing of the Carleton loan.

Solar Power Generation Segment

For the year ended December 31, 2013, this segment produced 103% of the LTA and generated revenues of \$16.8 million (compared with \$11.7 million in 2012). Better-than-average solar irradiation in the second and third quarters compensated for lower production in the first quarter caused by unusually large snowfalls and extremely cold weather that slowed the removal of snow from the solar panels. The 44% increase in revenues is due mainly to the full-year contribution of the Stardale solar farm, which was commissioned in May 2012.

For the year ended December 31, 2012, the solar power generation segment produced 106% of the LTA and generated revenues of \$11.7 million since the commissioning of the Stardale solar farm in May.

The decrease in total assets since December 31, 2012, results mainly from depreciation of property, plant and equipment as well as amortization of intangible assets.

The decrease in total liabilities since December 31, 2012, results mainly from scheduled repayment of long-term debt and the decrease in derivative financial instruments.

Site Development Segment

For the year ended December 31, 2013, site development expenses were \$5.6 million (compared with \$6.2 million in 2012). The decrease is due mainly to the Corporation operating a greater number of facilities in 2013 than in 2012, which resulted in a higher proportion of general and administrative expenses being allocated to the operating segment, and to lower prospective project expenses.

The decrease in total assets since December 31, 2012 is attributable mainly to the transfer of the Northwest Stave River facility to the hydroelectric generation segment, partly offset by payments made for costs incurred for the construction of the Kwoiek Creek project, the pre-construction activities and construction of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects and pre-construction activities of the Big Silver Creek and Mesgi'g Ugju's'n Development Projects.

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

QUARTERLY FINANCIAL INFORMATION

	Three-months ended						
(in millions of dollars, unless otherwise stated)	Dec. 31, 2013	Sept. 30, 2013	June 30, 2013	Mar. 31, 2013			
Power generated (MWh)	496,613	706,495	792,541	386,171			
Revenues	41.4	58.0	63.2	35.7			
Adjusted EBITDA	25.6	46.7	51.3	25.4			
Unrealized net (gain) loss on derivative							
financial instruments	(11.7)	(2.4)	(27.3)	(3.8)			
Net earnings (loss)	3.4	11.1	31.0	(0.2)			
Net earnings (loss) attributable to owners of							
the parent	6.3	10.8	28.3	2.8			
Net earnings (loss) attributable to owners of							
the parent (\$ per share – basic and diluted)	0.05	0.09	0.28	0.01			
Dividends declared on preferred shares	1.8	1.8	1.8	2.0			
Dividends declared on common shares	13.9	13.8	13.7	13.6			
Dividends declared on common shares (\$ per share)	0.145	0.145	0.145	0.145			

	Three-months ended						
(in millions of dollars, unless otherwise stated)	Dec. 31, 2012	Sept. 30, 2012	June 30, 2012	Mar. 31, 2012			
	(restated)	(restated)	(restated)	(restated)			
Power generated (MWh)	531,564	559,379	694,661	319,341			
Revenues	47.1	47.1	54.3	28.1			
Adjusted EBITDA	34.2	36.7	44.6	18.3			
Unrealized net (gain) loss on derivative							
financial instruments	(5.3)	(9.5)	27.1	(20.1)			
Net (loss) earnings	(0.6)	(0.7)	(11.9)	7.8			
Net earnings (loss) attributable to owners of							
the parent	1.8	(0.2)	(9.1)	8.9			
Net earnings (loss) attributable to owners of							
the parent (\$ per share – basic and diluted)	0.00	(0.01)	(0.12)	0.10			
Dividends declared on preferred shares	1.1	1.1	1.1	1.1			
Dividends declared on common shares	13.6	13.5	11.8	11.8			
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 production is 75% hydroelectric, this seasonality can be explained by water flows that are normally at their highest in the second quarter due to the snow melt season and at their lowest in the first quarter due to the cold temperatures, which limit precipitation in the form of rain. However, premiums for the electricity generated during the coldest months of the year included in some PPAs of the Corporation's hydroelectric facilities attenuate this seasonality. Wind regimes are generally best in the first quarter, while solar irradiation is at its highest during the summer months and at its lowest during the winter months.

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

Readers would expect the net earnings (loss) 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 that causes the largest fluctuations in net earnings (loss) is 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.

FOURTH QUARTER RESULTS

Operating Facilities

Three months	2013				2012			
ended December 31	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	143,454	144,310	99%	74.25	101,091	92,149	110%	83.24
Ontario	24,950	21,212	118%	69.81	22,590	21,212	106%	70.07
British Columbia	121,619	224,900	54%	87.14	215,583	221,143	97%	85.01
United States	2,845	5,223	54%	72.23	5,511	5,223	106%	68.32
Subtotal	292,868	395,645	74%	79.20	344,775	339,727	101%	83.24
WIND								
Quebec	197,884	207,276	95%	79.38	180,889	193,201	94%	87.77
SOLAR								
Ontario	5,861	5,866	100%	420.00	5,900	5,907	100%	420.63
Total	496,613	608,787	82%	83.29	531,564	538,835	99%	88.53

^{1.} As a result of the application of IFRS 11, 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.

For the three-month period ended December 31, 2013, the Corporation's facilities produced 496.6 GWh of electricity, or 82% of the LTA of 608.8 GWh. Overall, hydroelectric facilities produced 74% of their LTA, as above-average water flows at most facilities in Ontario and Quebec were not sufficient to compensate for below-average water flows in British Columbia and the United States. Production levels in British Columbia were affected by one of the driest years on record and also by a shutdown for capital improvements at the Miller Creek facility between August 8 and November 13. Overall, wind farms produced 95% of their LTA due to below-average wind conditions during the quarter, except Baie-des-Sables which experienced average wind conditions. The Stardale solar farm produced 100% of its LTA.

Revenues

For the three-month period ended December 31, 2013, the Corporation recorded revenues of \$41.4 million, compared with \$47.1 million in 2012, due mainly to below-average water flows in British Columbia and the United States, compared with above-average water flows in the same period last year, which more than offset the full-quarter contribution of the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, the addition of capacity at the Gros Morne wind farm in November 2012 and the acquisition of the Magpie hydroelectric facility in July 2013.

Expenses

For the three-month period ended December 31, 2013, the Corporation recorded operating expenses of \$11.0 million (\$9.3 million in 2012), general and administrative expenses of \$2.9 million (\$1.8 million in 2012) and prospective project expenses of \$1.9 million (\$1.8 million in 2012). The increase in expenses compared with the same period last year is due mainly to the Corporation operating a greater number of facilities.

^{2.} Including all payment adjustments related to the month, day and hour of delivery, to environmental attributes and to the ecoENERGY Initiative, as applicable.

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

Adjusted EBITDA

For the three-month period ended December 31, 2013, the Corporation recorded Adjusted EBITDA of \$25.6 million, compared with \$34.2 million in 2012, due mainly to below-average production as described above. The greater decrease in Adjusted EBITDA than in revenues is due mainly to the fact that operating and general and administrative expenses have increased as a result of the Corporation operating a greater number of facilities and that these expenses are not directly correlated to production levels.

Finance Costs

During the fourth quarter, finance costs were \$16.1 million (\$16.8 million in 2012).

Depreciation and Amortization

During the fourth quarter, depreciation and amortization expense totalled \$17.2 million (\$17.3 million in 2012).

Net Earnings (Loss)

For the three-month period ended December 31, 2013, the Corporation recorded net earnings of \$3.4 million (basic and diluted net earnings per share of \$0.05), compared with a net loss of \$0.6 million in 2012 (basic and diluted net loss per share of \$0.00). This improvement is due mainly to an unrealized gain on derivative financial instruments of \$11.7 million, compared with an unrealized gain of \$5.3 million in 2012, which offset the decrease in Adjusted EBITDA in the fourth quarter of 2013. Excluding the unrealized gains on derivative financial instruments and the related income taxes, the Corporation would have recognized a net loss of \$5.5 million for the fourth quarter ended December 31, 2013, compared with a net loss of \$4.9 million in 2012.

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

INVESTMENTS IN JOINT VENTURES

After applying IFRS 11, the Corporation's material joint ventures at the end of the reporting period were Umbata Falls, L.P. (49% interest) and 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

Year ended December 31		2013			2012			
	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	154,750	110,343	140%	78.02	101,934	110,343	92%	84.19
Viger-Denonville	8,720	8,809	99%	148.50	_		%	

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

Umbata Falls, L.P.

Umbata Falls' Summary Statements of Earnings and Comprehensive Income

	Year ended	December 31
	2013	2012
Revenues	12,073	8,581
Operating and general and administrative expenses	746	835
Adjusted EBITDA	11,327	7,746
Finance costs	2,501	2,536
Other net revenues	(34)	(20)
Depreciation and amortization	4,024	4,025
Unrealized net gain on derivative financial instruments	(4,694)	(448)
Net earnings and comprehensive income	9,530	1,653

For the year ended December 31, 2013, the increase in revenues and Adjusted EBITDA is due to above-average production generated by above-average water flows since the beginning of the year, compared with below-average water flows during the same period last year. The higher unrealized net gains on derivative financial instruments recorded in 2013 are due to the greater increase in benchmark interest rates since the end of 2012, compared with the same period last year.

Umbata Falls' Summary Statements of Financial Position

As at	December 31, 2013	December 31, 2012
Current assets	3,685	2,801
Non-current assets	75,864	79,679
Current liabilities	47,972	2,382
Non-current liabilities	1,852	53,225
Shareholders' equity	29,725	26,873

The Umbata Falls loan has been recorded in the current portion of long-term debt in view of its July 2014 term maturity. Umbata Falls, L.P. expects to refinance the outstanding balance by that date. In addition, 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 totaling \$46.7 million used to hedge the interest rate on 100% of the Umbata Falls loan had a net negative value of \$3.0 million at December 31, 2013 (negative \$7.7 million at December 31, 2012). This favourable difference is due mainly to an increase in benchmark interest rates since the end of 2012. The estimated impact of a 0.1% interest rate increase would decrease the interest rate swap-related liability by \$0.4 million. Conversely, a 0.1% interest rate decrease would increase the interest rate swap-related liability by \$0.4 million.

^{2.} Including payments received from the ecoENERGY Initiative for Umbata Falls.

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

Viger-Denonville, L.P.

Viger-Denonville's Summary Statements of Earnings and Comprehensive Income

	Year ended	Year ended December 31	
	2013	2012	
Revenues	1,295	_	
Operating and general and administrative expenses	131	9	
Adjusted EBITDA	1,164	(9)	
Finance costs	231	_	
Other net revenues	(3,720)	(59)	
Depreciation and amortization	369	_	
Unrealized net loss (gain) on derivative financial instruments	1,517	(663)	
Net earnings and comprehensive income	2,767	713	

For the year ended December 31, 2013, revenues and Adjusted EBITDA reflect the commissioning of the Viger-Denonville wind farm on November 19, 2013. Other net revenues reflect a realized gain on derivative financial instruments of \$2.2 million, as discussed below, and a \$1.5 million gain on foreign exchange contracts that were used to secure the exchange rate on planned equipment purchases for the project. The unrealized net loss on derivative financial instruments recorded in 2013, stems from the reversal of the unrealized gain upon settlement of the bond forward contracts in the third quarter of 2013 and to an unrealized loss on the interest rate swap entered into on August 7, 2013, due to a decrease in the benchmark interest rate between then and December 31, 2013.

Viger-Denonville's Summary Statements of Financial Position

As at	December 31, 2013	December 31, 2012
Current assets	9,221	4,791
Non-current assets	63,940	7,274
Current liabilities	8,200	200
Non-current liabilities	44,813	328
Shareholders' equity	20,148	11,537

The increase in balance sheet items is due the construction activities and commissioning of the Viger-Denonville wind project. The increase in shareholders' equity is due to the net earnings of \$2.8 million recognized in 2013 and to a net equity investment of \$2.9 million made by each of the partners.

Also during 2013, loans were made to the Viger-Denonville project until such time as the project-level financing was put in place or drawn. These loans bore interest at the same rate as the Corporation paid to its lenders on the revolving term credit facility, plus a margin, and were reimbursed prior to the end of 2013.

On August 7, 2013, Viger-Denonville, L.P. settled the bond forward contracts simultaneously with the closing of the interest-swapped long-term financing for the project, which resulted in Viger-Denonville, L.P. recognizing a realized gain on derivative financial instruments of \$2.2 million during the third quarter. This gain results from the increase in benchmark interest rates between the date the bond forwards were entered into (December 2012 and February 2013) and the settlement date (August 2013) and compensates for the higher fixed interest rate on the Viger-Denonville loan for its 18-year term.

Viger-Denonville, L.P. uses derivative financial instruments 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. During the third quarter, Viger-Denonville, L.P. settled bond forward contracts and entered into an interest rate swap contract of \$58.5 million to hedge the interest rate on 95% of its loan. The estimated impact of a 0.1% interest rate increase would decrease the interest rate swap-related liability by \$0.4 million. Conversely, a 0.1% interest rate decrease would increase the interest rate swap-related liability by \$0.4 million.

(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 L.P. and Its Eight Subsidiaries

Harrison Hydro's Summary Statements of Earnings and Comprehensive Income

	Year ended December 31	
	2013	2012
Revenues	47,196	51,943
Adjusted EBITDA	36,094	40,672
Net loss and comprehensive loss	(8,201)	(3,917)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(4,751)	(2,448)
Non-controlling interests	(3,450)	(1,469)
	(8,201)	(3,917)

For the year ended December 31, 2013, the decrease in revenues and Adjusted EBITDA and the greater net loss are due mainly to below-average production resulting from below-average water flows during the year compared with the same period last year.

Harrison Hydro's Summary Statements of Financial Position

As at	December 31, 2013	December 31, 2012
Current assets	30,143	69,089
Non-current assets	662,749	680,279
Current liabilities	13,925	16,588
Non-current liabilities	460,511	459,221
Equity attributable to owners	130,497	158,706
Non-controlling interests	87,959	114,853

As at December 31, 2013, the decrease in non-current assets is due mainly to depreciation of fixed assets. Furthermore, the Harrison Operating Facilities distributed \$13.6 million in 2013 (\$46.9 million in 2012). The funds were distributed in the form of non-interest bearing loans to the Corporation and its partners. The loans of \$6.8 million (\$23.4 million in 2012) were presented as loans to partners at year end. On January 1, 2014, the \$6.8 million loans were reimbursed (the \$23.4 million loans were reimbursed in June 2013) directly from distributions from the Harrison Operating Facilities, and a corresponding decrease in non-controlling interests was recorded in 2014 (in 2013) with no impact to cash flows.

Harrison Hydro's Summary Statements of Cash Flows

	Year ended [Year ended December 31	
	2013	2012	
Net cash inflow from operating activities	13,908	19,804	
Net cash outflow from financing activities	(7,877)	(7,530)	
Net cash outlow from investing activities	(9,751)	(461)	
Net (decrease) increase in cash and cash equivalents	(3,720)	11,813	

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

Creek Power Inc. and Its Six Subsidiaries

Creek Power's Summary Statements of Earnings and Comprehensive Income

	Year ended December 31	
	2013	2012
Revenues	2,346	2,340
Adjusted EBITDA	(20)	725
Net earnings (loss) and comprehensive earnings (loss)	2,331	(3,681)
Net earnings (loss) and comprehensive earnings (loss) attributable to:		
Owners of the parent	1,570	(2,514)
Non-controlling interest	761	(1,167)
	2,331	(3,681)

For the year ended December 31, 2013, the negative Adjusted EBITDA is due mainly to higher prospective project expenses than last year, while the recognition of net earnings is due mainly to an unrealized net gain on derivative financial instruments resulting from the increase in benchmark interest rates since December 31, 2012, compared with a much smaller increase in benchmark interest rates during 2012.

Creek Power's Summary Statements of Financial Position

As at	December 31, 2013	December 31, 2012
Current assets	6,593	1,358
Non-current assets	67,349	40,010
Current liabilities	13,547	8,987
Non-current liabilities	69,534	43,852
Deficit attributable to owners	(9,897)	(11,468)
Non-controlling interest	758	(3)

The increase in balance sheet items is due mainly to pre-construction spending for the Upper Lillooet River and Boulder Creek projects.

Creek Power's Summary Statements of Cash Flows

	Year ende	Year ended December 31	
	2013	2012	
Net cash inflow from operating activities	731	1,739	
Net cash inflow from financing activities	19,485	2,531	
Net cash outflow from investing activities	(20,661)	(4,085)	
Net (decrease) increase in cash and cash equivalents	(445)	185	

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

Kwoiek Creek Resources L.P.

Kwoiek Creek Resources's Summary Statements of Earnings and Comprehensive Income

	Year ended December 31	
	2013	2012
Revenues	7	_
Adjusted EBITDA	(11)	(12)
Net earnings (loss) and comprehensive earnings (loss)	7	(8,077)
Net earnings (loss) and comprehensive earnings (loss) attributable to:		
Owners of the parent	13	(4,036)
Non-controlling interest	(6)	(4,041)
	7	(8,077)

The net losses recorded in 2012 were due mainly to a \$14.1 million realized loss on derivative financial instruments, partly offset by an unrealized gain on derivative financial instruments of \$6.1 million, upon closing of the financing for the Kwoiek Creek facility.

Kwoiek Creek Resources's Summary Statements of Financial Position

As at	December 31, 2013	December 31, 2012
Current assets	34,019	88,502
Non-current assets	177,928	113,796
Current liabilities	23,694	17,529
Non-current liabilities	202,901	199,424
Deficit attributable to owners	(7,514)	(7,527)
Non-controlling interests	(7,134)	(7,128)

The increase in balance sheet items is due mainly to the ongoing construction activities for the Kwoiek Creek project. The decrease in current assets reflects the drawings on restricted cash as costs were incurred. This facility was completed in December 2013 and commissioned effective January 1, 2014. Non-current liabilities include loans by the partners to Kwoiek Creek Resources Limited Partnership. The loans bear interests at a rate 14%. The partner's loan made to Kwoiek Creek Resources Limited Partnership amounts to \$3.7 million. The Corporation's loan made to Kwoiek Creek Resources Limited Partnership, which is eliminated in the financial statement consolidation process, amounts to \$55.5 million as at December 31, 2013.

Kwoiek Creek Resources's Summary Statements of Cash Flows

	Year ended Dec	Year ended December 31	
	2013	2012	
Net cash outflow from operating activities	(4,499)	(14,049)	
Net cash inflow from financing activities	3,391	183,317	
Net cash outflow from investing activities	(3,012)	(163,108)	
Net (decrease) increase in cash and cash equivalents	(4,120)	6,160	

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

RISKS AND UNCERTAINTIES

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

Execution of Strategy

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

The successful execution of this strategy requires careful timing and business judgment, as well as the resources to complete the development of power generating facilities. There is no certainty that the Corporation will be able to acquire or develop high-quality power production facilities at attractive prices to supplement its growth. The Corporation may also underestimate the costs necessary to bring power generating facilities into commercial operation or may be unable to quickly and efficiently integrate new acquisitions into its existing operations.

Capital Resources

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

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

Derivative Financial Instruments

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

Hydrology, Wind and Solar Regime

The amount of electricity generated by the Corporation's hydroelectric facilities depends on the availability of water flows. There is no certainty that the long-term availability of such resources will remain unchanged. Poor hydrological conditions at any of the Corporation's hydroelectric facilities may reduce the Corporation's revenues and profitability. In addition, in the event of severe flooding, the Corporation's hydroelectric facilities may be damaged.

Similarly, the amount of electricity generated by the Corporation's wind farms depends on the availability of wind, which is naturally variable. Higher or lower wind regimes at any of the Corporation's wind farms may reduce the Corporation's revenues and profitability.

Finally, the amount of electricity generated by the Corporation's solar farms depends on the availability of solar irradiation, which is naturally variable. Lower solar irradiation levels at any of the Corporation's solar farms may reduce the Corporation's revenues and profitability.

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

Construction Cost Overruns and Design Flaws

Delays and cost overruns may occur in completing the construction of the Development Projects, the Prospective Projects and future projects that the Corporation will undertake. Factors that could cause such delays or cost overruns include, without limitation, permitting delays, construction pricing escalation, changing engineering and design requirements, contractor performance, labour disruptions, adverse weather conditions and the availability of financing. Cost overruns during the operation of facilities may also occur as a result of design or manufacturing flaws, which may not all be covered by warranty. Also, mechanical breakdown of equipment may occur after the expiration of the warranty, resulting in loss of production as well as the cost of repairs. In addition, if the Development Projects are not brought into commercial operation within the time period stipulated in their PPA, the Corporation may be subject to penalties or the counterparty may be entitled to terminate the PPA.

Health, Safety and Environmental Risks

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

Development of New Facilities

The Corporation participates in the development and construction of new power generating facilities. These projects have greater uncertainty surrounding future profitability than existing Operating Facilities with established track records. Many factors affecting costs may not have been determined yet, such as land royalty payments, water royalties and municipal taxes. In other cases, the Corporation is required to advance funds and post performance bonds in the course of developing these projects. In the event that some of these projects are not completed or do not operate according to specifications, or that unforeseen costs or taxes are incurred, the Corporation could be adversely affected.

Permits

The Corporation does not currently hold all of the approvals, licenses and permits required for the construction and operation of the Development Projects or the Prospective Projects, including environmental approvals and permits necessary to construct and operate the Development Projects or the Prospective Projects. Failure to obtain or delays in obtaining all necessary licenses, approvals or permits, including renewals thereof or modifications thereto, could result in the delay or termination of the Development Projects or Prospective Projects. There can be no assurance that any one Prospective Project will result in an actual Operating Facility. In addition, federal and provincial environmental permits to be issued in connection with any of the Development Projects may contain conditions that need to be satisfied prior to or during construction of the Development Projects or during and after the operation of the Operating Facilities. It is not possible to forecast the conditions imposed by such permits or the cost of any mitigating measures required by such permits in the future.

Project Performance and Penalties

The ability of the Corporation's facilities to generate the maximum amount of power that can be sold to Hydro-Québec, BC Hydro and the OPA or other purchasers of electricity under PPAs is an important determinant of the Corporation's revenues. If one of the Corporation's facilities delivers less than the required quantity of electricity in a given contract year or is otherwise in default under its PPA, the Corporation may have to pay a penalty to the relevant power purchaser, which could adversely affect its revenues and profitability.

Equipment Failure

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

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

Interest Rate and Refinancing Risk

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

Financial Leverage and Restrictive Covenants

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

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

Declaration of Dividends at the Discretion of the Board

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

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

Securing New Power Purchase Agreements

Securing new PPAs is a key component of the Corporation's growth strategy, and therefore constitutes a risk factor given the competitive environment in which the Corporation operates. The Corporation expects to continue to enter into PPAs for the sale of its power, which PPAs are mainly obtained through participation in competitive bid processes. During these processes, the Corporation faces competitors ranging from large utilities to small independent power producers, some of which have significantly greater financial and other resources than the Corporation. There is no assurance that the Corporation will be awarded a PPA following any future competitive bid process or that existing PPAs will be renewed, or that they will be renewed on equivalent terms and conditions upon the expiry of their respective terms.

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

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. During the reporting period, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment, intangible assets and project development costs, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives. These estimates and assumptions are based on current market conditions, management's planned course of action and assumptions about future business and economic conditions. Changes in the underlying assumptions and estimates could have a material impact on the reported amounts. These estimates are reviewed periodically. If adjustments prove necessary, they are recognized in earnings in the period in which they are made. Changes made during the year ended December 31, 2013, are described in the "Accounting Changes" section. Other significant accounting policies are listed in Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2013.

ACCOUNTING CHANGES

Application of New and Revised Standards on Consolidation, Joint Arrangements, Associates and Disclosures

In May 2011, a package of five standards on consolidation, joint arrangements, associates and disclosures were issued including IFRS 10 Consolidated Financial Statements, IFRS 11 Joint Arrangements, IFRS 12 Disclosures of Interest in Other Entities, IAS 27 (as revised in 2011) Separate Financial Statements and IAS 28 (as revised in 2011) Investments in Associates and Joint Ventures. In the current year, the Corporation has adopted these standards, except for IAS 27 which is not applicable as it deals only with separate financial statements. The impact of the application of these standards is described below.

Impact of the Application of IFRS 10

IFRS 10 replaces the sections of IAS 27 Separate Financial Statements that dealt with consolidated financial statements and SIC-12 Consolidation- Special Purpose Entities. IFRS 10 changes the definition of control such that an investor controls an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. To meet the definition of control in IFRS 10, all of the three criteria, including (a) an investor has power over an investee, (b) the investor has exposure, or rights, to variable returns from its involvement with the investee, and (c) the investor has the ability to use its power over the investee to affect the amount of the investor's returns, must be met. Previously, control was defined as the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. Much more guidance has been included in IFRS 10 to explain when an investor has control over an investee. In particular, detailed guidance has been established in IFRS 10 to explain when an investor that owns less than 50 per cent of the voting shares in an investee has control over the investee. For example, in assessing whether or not an investor with less than a majority of the voting rights in an investee has a sufficiently dominant voting interest to meet the power criterion, IFRS 10 requires the investor to take into account all relevant facts and circumstances, particularly, the size of the investor's holding of voting rights relative to the size and dispersion of holdings of the other vote holders.

The application of IFRS 10 has not affected the accounting for the Corporation since the management concluded that all entities that were consolidated still met the criteria for the new definition of control and need to be consolidated.

Impact of the Application of IFRS 11

IFRS 11 replaces IAS 31 Interests in Joint Ventures and SIC-13 Jointly Controlled Entities - Non Monetary Contributions by Venturers. IFRS 11 deals with how a joint arrangement of which two or more parties have joint control should be classified. Under IFRS 11, there are only two types of joint arrangements - joint operations and joint ventures. The classification of joint arrangements under IFRS 11 is determined based on the rights and obligations of parties to the joint arrangements by considering the structure, the legal form of the arrangements, the contractual terms agreed by the parties to the arrangement, and, when relevant, other facts and circumstances. A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement (i.e. joint operators) have rights to the assets, and obligations for the liabilities, relating to the arrangement. A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement (i.e. joint venturers) have rights to the net assets of the arrangement. Previously, IAS 31 Interests in Joint Ventures had three types of joint arrangements - jointly controlled entities, jointly controlled operations and jointly controlled assets. The classification of joint arrangements under IAS 31 was primarily determined based on the legal form of the arrangement (e.g. a joint arrangement that was established through a separate entity was accounted for as a jointly controlled entity).

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

The subsequent accounting of joint ventures and joint operations is different. Investments in joint ventures are accounted for using the equity method (proportionate consolidation is no longer allowed). Investments in joint operations are accounted for such that each joint operator recognizes and measures the assets and liabilities (and the related revenues and expenses) in relation to its interest in the arrangement in accordance with the applicable standards.

Upon applying IFRS 11, the Corporation reviewed and assessed the legal form and terms of the contractual arrangements in relation to the Corporation's investments in joint arrangements. The application of IFRS 11 has changed the classification and subsequent accounting of the Corporation's investments in Umbata Falls, L.P. and Parc éolien communautaire Viger-Denonville, s.e.c. ("Viger-Denonville, L.P."), which were classified as jointly controlled entities under the previous standard and were accounted for using the proportionate consolidation method. Under IFRS 11, Umbata Falls, L.P. and Viger-Denonville, L.P. are treated as joint ventures and the Corporation's interests into them are required to be accounted for using the equity method.

The change in accounting of the Corporation's investment in Umbata Falls, L.P. and Viger-Denonville, L.P. has been applied in accordance with the relevant transitional provisions. The initial investment as at January 1, 2012 for the purposes of applying the equity method is measured as the aggregate of the carrying amounts of the assets and liabilities that the Corporation had previously proportionately consolidated. Such a change in accounting has affected the amounts reported in the Corporation's consolidated financial statements.

All comparative figures for the year ended December 31, 2012, and December 31, 2011, have been adjusted to reflect the presentation changes arising from application of IFRS 11.

Impact of the Application of IFRS 12

IFRS 12 is a disclosure standard and is applicable to entities that have interests in subsidiaries, joint arrangements, associates and/or unconsolidated structured entities. The application of IFRS 12 has resulted in more extensive disclosures appearing in notes 10, 29 and 30 of the audited financial statements.

IFRS 13, Fair Value Measurement

IFRS 13, Fair Value Measurement, replaces the fair value measurement guidance currently dispersed across different IFRS standards with a single definition of fair value and a comprehensive framework for measuring fair value when such measurement is required under other IFRSs. It also establishes disclosure requirements about fair value measurements. These standards have been adopted and applied in these consolidated financial statements. The application of these standards has not had any impact on the amounts reported for the current or prior year.

Change in Useful Life for the Amortization Period of Intangible Assets

As of July 1, 2013, the Corporation changed the useful life for the amortization period for the intangible assets related to certain Quebec hydroelectric facilities. The estimated useful life, which was formerly equal to the first term of the respective Power Purchase Agreements ("PPAs") was increased by 20 to 25 years, which reflects the PPA's renewable rights periods. This change in accounting estimate arose from the Corporation's intention to exercice its option to renew its PPAs. This change in estimate was recorded prospectively. The estimated annual impact of this change in accounting estimate is a decrease of approximately \$3.6 million in annual amortization expense for the next 12 months and will be declining in future periods. The impact of this change for the period ended December 31, 2013 is a \$1.8 million decrease in amortization expense.

New IFRS issued but not yet effective

IFRS 9 - Financial Instrument

As part of the project to replace IAS 39, Financial Instruments: Recognition and Measurement, this standard retains but simplifies the mixed measurement model and establishes two primary measurement categories for financial assets. More specifically, the standard:

- Deals with classification and measurement of financial assets;
- Establishes two primary measurement categories for financial assets: amortized cost and fair value;
- Prescribes that classification depends on entity's business model and the contractual cash flow characteristics
 of the financial asset:
- Eliminates the existing categories: held-to-maturity, available-for-sales, and loans and receivables.

Certain changes were also made regarding the fair value option for financial liabilities and accounting for certain derivatives linked to unquoted equity instruments.

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

In July 2013, the International Accounting Standards Board ("IASB") decided to temporarily defer the mandatory effective date of IFRS 9 and to not specify that date until the requirement for financial instrument classification and measurement and financial asset impairment are finalized. The Corporation is monitoring the progress of the IASB's work.

IFRIC 21 Levies

In May 2013, the 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. IFRIC 21 is effective for annual periods commencing on or after January 1, 2014. The Corporation is currently evaluating the impact the final interpretation is expected to have on its consolidated financial statements.

SUBSEQUENT EVENTS

Commissioning of the Kwoiek Creek Hydroelectric Facility

On February 18, 2014, the Corporation announced that the Kwoiek Creek Resources Limited Partnership has begun commercial operation of the Kwoiek Creek run-of-river hydroelectric facility located in British Columbia, Canada. Innergex holds 50% of Kwoiek Creek Resources Limited Partnership, and is responsible for the management of the construction and the operation of the facility. The Kanaka Bar Indian Band holds the remaining 50% interest. The 49.9 MW Kwoiek Creek hydroelectric facility is located partly on Crown lands and partly on reserve lands, approximately 14 km south of Lytton, British Columbia. Construction began in 2011 and was completed in early December, on time and on budget. While commissioning of the facility began at that time, the Corporation and BC Hydro have amended their agreement to clarify stipulated production levels, subject to approval by the British Columbia Utilities Commission. Once the approval is received, BC Hydro will accept the COD Certificate with an effective commissioning date of January 1, 2014 for the Kwoiek Creek facility. For more information on the Kwoiek Creek facility, please refer to the "Commissioning Activities" and the "Non-wholly owned subsidiaries" sections.

Commissioning of the Northwest Stave River Hydroelectric Facility

On February 24, 2014, the Corporation announced the commissioning of the Northwest Stave River run-of-river hydroelectric facility located in British Columbia, Canada. This facility is located on Crown land, approximately 50 km north of Mission, British Columbia. Construction began in 2011 and was completed in early December 2013, on time and on budget. Commissioning of the facility began at that time and the COD certificate has now been approved by BC Hydro with an effective commissioning date of December 18, 2013. For more information on the Northwest Stave River facility, please refer to the "Commissioning Activities" section.

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.

Responsibility for Financial Reporting

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

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

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

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

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

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

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

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

[s] Jean Perron
Jean Perron, CPA, CA
Chief Financial Officer and
Senior Vice President

Innergex Renewable Energy Inc.

Longueuil, Canada, February 25, 2014



INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Innergex Renewable Energy Inc.

We have audited the accompanying consolidated financial statements of Innergex Renewable Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2013, December 31, 2012 and January 1, 2012, and the consolidated statements of earnings, consolidated statements of comprehensive income (loss), consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years ended December 31, 2013 and December 31, 2012, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Innergex Renewable Energy Inc. as at December 31, 2013, December 31, 2012 and January 1, 2012, and its financial performance and its cash flows for the years ended December 31, 2013 and December 31, 2012 in accordance with International Financial Reporting Standards.

Deloite LLP

Montreal, Quebec February 25, 2014

1 CPA auditor, CA, public accountancy permit No. A109248

CONSOLIDATED STATEMENTS OF EARNINGS

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

		Year ended December 31	
		2013	2012
	Notes		(restated - note 2.2.1)
Payanua		100 250	176 655
Revenues Expenses		198,259	176,655
Operating	7	33,947	28,850
General and administrative	,	11,194	9,601
Prospective projects		4,202	4,412
Prospective projects		4,202	4,412
Earnings before finance costs, income taxes, depreciation, amortization, other net (revenues) expenses, share of earnings of joint ventures and unrealized net gain on derivative financial instruments		148,916	133,792
Finance costs	8	65,158	62,038
Other net (revenues) expenses	9	(392)	15,566
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on derivative financial instruments		84,150	56,188
Depreciation	7,18	48,674	42,602
Amortization	7,19	20,486	21,163
Share of earnings of joint ventures	10	(6,053)	(1,166)
Unrealized net gain on derivative financial instruments	6	(45,249)	(7,791)
Earnings before income taxes		66,292	1,380
Provision for income taxes			
Current	13	2,618	1,970
Deferred	13	18,243	4,793
		20,861	6,763
Net earnings (loss)		45,431	(5,383)
Net earnings (loss) attributable to:		40 470	4.405
Owners of the parent	00.0	48,170	1,405
Non-controlling interests	29.2	(2,739)	(6,788)
		45,431	(5,383)
Weighted average number of common shares outstanding (in 000s)	14	94,694	86,557
Basic net earnings (loss) per share	14	0.43	(0.03)
, , , , , , , , , , , , , , , , , , ,			(12)
Diluted weighted average number of common shares outstanding (in 000s)	14	94,780	86,708
Diluted net earnings (loss) per share	14	0.43	(0.03)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

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

	Year ended December 31				
	2013	2012			
		(restated - note 2.2.1)			
Net earnings (loss)	45,431	(5,383)			
Items of comprehensive income (loss) that will be subsequently reclassified to profit or loss:					
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	356	(90)			
Deferred income tax (provision) recovery	(46)	12			
Foreign exchange (loss) gain on the designated portion of the US dollar denominated debt used as hedge on the investment in self-sustaining					
foreign subsidiaries	(352)	104			
Deferred income tax recovery (provision)	45	(13)			
Other comprehensive income for the year	3	13			
Total comprehensive income (loss)	45,434	(5,370)			
T-4-1					
Total comprehensive income (loss) attributable to:					
Owners of the parent	48,173	1,418			
Non-controlling interests	(2,739)	(6,788)			
	45,434	(5,370)			

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at		December 31, 2013	December 31, 2012	January 1, 2012
	Notes		(restated - note 2.2.2)	(restated - note 2.2.3)
Assets				
Current assets				
Cash and cash equivalents		34,267	49,496	34,863
Restricted cash and short-term investments	15	49,745	87,811	53,415
Accounts receivable	16	19,799	50,062	36,558
Reserve accounts	17	1,771	1,816	_
Income tax receivable	13	80	443	1,664
Derivative financial instruments	6	7,563	1,693	1,791
Loans to related parties	31	6,798	23,444	_
Prepaid and others		5,085	4,715	3,977
		125,108	219,480	132,268
Reserve accounts	17	45,791	45,800	41,239
Property, plant and equipment	18	1,583,417	1,427,112	1,231,710
Intangible assets	19	466,093	429,424	429,512
Project development costs	20	81,643	103,529	97,241
Investments in joint ventures	10	24,639	18,935	14,499
Derivative financial instruments	6	7,066	6,698	8,248
Deferred tax assets	13	1,804	5,846	24,485
Goodwill	21	8,269	8,269	8,269
Other long-term assets	3	33,244	31,347	17,998
		2,377,074	2,296,440	2,005,469

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at		December 31, 2013	December 31, 2012	January 1, 2012
	Notes		(restated - note 2.2.2)	(restated - note 2.2.3)
Liabilities				
Current liabilities				
Dividends payable to shareholders		15,651	14,643	12,848
Accounts payable and other payables	22	48,258	41,252	26,559
Income tax liabilities	13	2,216	1,541	2,835
Derivative financial instruments	6	12,915	17,199	19,060
Current portion of long-term debt	23	26,649	63,926	18,982
Current portion of other liabilities	24	362	_	983
		106,051	138,561	81,267
Construction holdbacks		1,347	1,668	2,081
Derivative financial instruments	6	26,081	60,808	68,386
Accrual for acquisition of long-term assets		9,855	12,899	41,267
Long-term debt	23	1,313,718	1,166,782	1,006,646
Other liabilities	24	10,567	8,870	6,762
Liability portion of convertible debentures	25	79,831	79,655	79,490
Deferred tax liabilities	13	163,689	139,265	140,454
		1,711,139	1,608,508	1,426,353
Shareholders' equity				
Common share capital	26 a)	10,374	120,500	1
Contributed surplus from reduction of capital on common shares	26 b)	784,482	656,281	656,281
Preferred shares	26 c)	131,069	131,069	82,589
Share-based payment	26 d)	1,806	1,511	1,361
Equity portion of convertible debentures	25	1,340	1,340	1,340
Deficit		(344,809)	(330,621)	(277,083)
Accumulated other comprehensive income		244	241	228
Equity attributable to owners		584,506	580,321	464,717
Non-controlling interests		81,429	107,611	114,399
Total shareholders' equity		665,935	687,932	579,116
		2,377,074	2,296,440	2,005,469

Commitments and contingencies (see Note 33).

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

				Equity a	attributable to	owners				_	
For the year ended December 31, 2013	Number of Common shares (In 000s)	Common share 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)							48,170		48,170	(2,739)	45,431
Other items of comprehensive income								3	3		3
Total comprehensive income	_	_	_	_	_	_	48,170	3	48,173	(2,739)	45,434
Common shares issued through dividend reinvestment plan	1,995	18,075							18,075		18,075
Reduction of capital on Common shares (Note 26b))		(128,201)	128,201						_		_
Share-based payment		, ,			295				295		295
Business acquisitions (Note 5.1)										1	1
Distributions to non- controlling interests (Note 31)										(23,444)	(23,444)
Dividends declared on Common shares							(54,967)		(54,967)		(54,967)
Dividends declared on Preferred shares							(7,391)		(7,391)		(7,391)
Balance December 31, 2013	95,655	10,374	784,482	131,069	1,806	1,340	(344,809)	244	584,506	81,429	665,935

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

				Equity attr	ibutable to	owners					
For the year ended December 31, 2012	Number of Common shares (In 000s)	Common share 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, 2012	81,282	1	656,281	82,589	1,361	1,340	(277,083)	228	464,717	114,399	579,116
Net earnings (loss)							1,405		1,405	(6,788)	(5,383)
Other items of comprehensive income (loss)								13	13		13
Total comprehensive income (loss)	_	_	_		_		1,405	13	1,418	(6,788)	(5,370)
Common shares issued on July 26, 2012	12,041	123,656							123,656		123,656
Issuance fees (Net of \$2,403 of deferred income taxes)		(6,747)							(6,747)		(6,747)
Common shares issued through dividend reinvestment plan	279	2,935							2,935		2,935
Series C Preferred shares issued on December 11, 2012				50,000					50,000		50,000
Issuance fees (Net of \$526 of deferred income taxes)				(1,520)					(1,520)		(1,520)
Shares options exercised	58	655		(1,520)	(148)				507		507
Share-based payment					298				298		298
Dividends declared on Common shares							(50,693)		(50,693)		(50,693)
Dividends declared on Preferred shares							(4,250)		(4,250)		(4,250)
Balance December 31, 2012	93,660	120,500	656,281	131,069	1,511	1,340	(330,621)	241	580,321	107,611	687,932

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Year ended December 31			
		2013	2012		
	Notes		(restated - note 2.2.4)		
Operating activities					
Net earnings (loss)		45,431	(5,383)		
Items not affecting cash:					
Depreciation		48,674	42,602		
Amortization		20,486	21,163		
Share of earnings of joint ventures		(6,053)	(1,166)		
Unrealized net gain on derivative financial instruments		(45,249)	(7,791)		
Inflation compensation interest	8	1,892	3,362		
Amortization of financing fees	8	902	729		
Amortization of revaluation of long-term debt and convertible	0	1.055	1 526		
debentures	8	1,955	1,526		
Accretion expenses on other liabilities	8	546	450		
Share-based payment		295	298		
Deferred income taxes		18,243	4,793		
Effect of exchange rate fluctuations	•	398	(85)		
Write-off of project development costs	9	222	_		
Others		(86)	353		
Interest on long-term debt and convertible debentures	8	59,823	55,971		
Interest paid		(59,741)	(56,062)		
Gain on contingent considerations	9	(19)	(357)		
Contingent considerations paid		_	(983)		
Distributions received from joint ventures		3,272	955		
Provision for current income taxes	13	2,618	1,970		
Net income taxes paid		(1,606)	(2,039)		
		92,003	60,306		
Changes in non-cash operating working capital items	28	30,283	601		
		122,286	60,907		
Financing activities					
Dividends paid on Common shares		(36,602)	(45,963)		
Dividends paid on Preferred shares		(6,673)	(4,250)		
Increase of long-term debt		186,627	405,657		
Repayment of long-term debt		(145,321)	(201,751)		
Payment of deferred financing costs		(3,066)	(4,248)		
Net proceeds from issuance of Common shares		_	114,571		
Net proceeds from issuance of Preferred shares		(353)	48,350		
Proceeds from exercise of share options	26 d)		507		
<u> </u>		(5,388)	312,873		

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Year ended December 31			
		2013	2012		
	Notes		(restated - note 2.2.4)		
Investing activities					
Cash acquired on business acquisitions	5	1,885	_		
Business acquisitions	5	(28,577)	(68,635)		
Decrease (increase) of restricted cash and short-term investments	3	38,066	(34,396)		
Loans to related parties	31	(6,798)	(23,444)		
Net funds withdrawn from (invested into) the reserve accounts		527	(6,391)		
Additions to property, plant and equipment		(103,680)	(186,760)		
Additions to intangible assets		(27)	(1,929)		
Additions to project development costs		(27,799)	(5,495)		
Investments in joint ventures		(2,923)	(4,225)		
Additions to other long-term assets		(2,962)	(27,892)		
Proceeds from disposal of property, plant and equipment		76	56		
		(132,212)	(359,111)		
Effects of exchange rate changes on cash and cash equivalents		85	(36)		
Net (decrease) increase in cash and cash equivalents		(15,229)	14,633		
Cash and cash equivalents, beginning of year		49,496	34,863		
Cash and cash equivalents, end of year		34,267	49,496		
Cash and cash equivalents is comprised of:					
Cash		23,518	34,878		
Short-term investments		10,749	14,618		
		34,267	49,496		

Additional information is presented in Note 28.

NOTES TO THE 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 consolidated financial statements were approved by the Board of Directors on February 25, 2014.

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

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

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

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

2. APPLICATION OF NEW AND REVISED IFRS

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

Application of new and revised Standards on consolidation, joint arrangements, associates and disclosures

In May 2011, a package of five standards on consolidation, joint arrangements, associates and disclosures were issued including IFRS 10 Consolidated Financial Statements, IFRS 11 Joint Arrangements, IFRS 12 Disclosures of Interest in Other Entities, IAS 27 (as revised in 2011) Separate Financial Statements and IAS 28 (as revised in 2011) Investments in Associates and Joint Ventures. In the current year, the Corporation has adopted these standards, except for IAS 27 which is not applicable as it deals only with separate financial statements.

The impact of the application of these standards is set out below:

Impact of the application of IFRS 10

IFRS 10 replaces the sections of IAS 27 Separate Financial Statements that dealt with consolidated financial statements and SIC-12 Consolidation- Special Purpose Entities. IFRS 10 changes the definition of control such that an investor controls an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. To meet the definition of control in IFRS 10, all of the three criteria, including (a) an investor has power over an investee, (b) the investor has exposure, or rights, to variable returns from its involvement with the investee, and (c) the investor has the ability to use its power over the investee to affect the amount of the investor's returns, must be met. Previously, control was defined as the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. Much more guidance has been included in IFRS 10 to explain when an investor has control over an investee. In particular, detailed guidance has been established in IFRS 10 to explain when an investor that owns less than 50 per cent of the voting shares in an investee has control over the investee. For example, in assessing whether or not an investor with less than a majority of the voting rights in an investee has a sufficiently dominant voting interest to meet the power criterion, IFRS 10 requires the investor to take into account all relevant facts and circumstances, particularly, the size of the investor's holding of voting rights relative to the size and dispersion of holdings of the other vote holders.

The application of IFRS 10 has not affected the accounting for the Corporation since the management concluded that all entities that were consolidated still met the criteria for the new definition of control and need to be consolidated.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

Impact of the application of IFRS 11

IFRS 11 replaces IAS 31 Interests in Joint Ventures and SIC-13 Jointly Controlled Entities - Non Monetary Contributions by Venturers. IFRS 11 deals with how a joint arrangement of which two or more parties have joint control should be classified. Under IFRS 11, there are only two types of joint arrangements - joint operations and joint ventures. The classification of joint arrangements under IFRS 11 is determined based on the rights and obligations of parties to the joint arrangements by considering the structure, the legal form of the arrangements, the contractual terms agreed by the parties to the arrangement, and, when relevant, other facts and circumstances. A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement (i.e. joint operators) have rights to the assets, and obligations for the liabilities, relating to the arrangement. A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement (i.e. joint venturers) have rights to the net assets of the arrangement. Previously, IAS 31 Interests in Joint Ventures had three types of joint arrangements - jointly controlled entities, jointly controlled operations and jointly controlled assets. The classification of joint arrangements under IAS 31 was primarily determined based on the legal form of the arrangement (e.g. a joint arrangement that was established through a separate entity was accounted for as a jointly controlled entity).

The subsequent accounting of joint ventures and joint operations is different. Investments in joint ventures are accounted for using the equity method (proportionate consolidation is no longer allowed). Investments in joint operations are accounted for such that each joint operator recognizes and measures the assets and liabilities (and the related revenues and expenses) in relation to its interest in the arrangement in accordance with the applicable standards.

Upon applying IFRS 11, the Corporation reviewed and assessed the legal form and terms of the contractual arrangements in relation to the Corporation's investments in joint arrangements. The application of IFRS 11 has changed the classification and subsequent accounting of the Corporation's investments in Umbata Falls, L.P. and Parc éolien communautaire Viger-Denonville, s.e.c. ("Viger-Denonville, L.P."), which were classified as jointly controlled entities under the previous standard and were accounted for using the proportionate consolidation method. Under IFRS 11, Umbata Falls, L.P. and Viger-Denonville, L.P. are treated as joint ventures and the Corporation's interests into them are required to be accounted for using the equity method.

The change in accounting of the Corporation's investment in Umbata Falls, L.P. and Viger-Denonville, L.P. has been applied in accordance with the relevant transitional provisions. The initial investment as at January 1, 2012 for the purposes of applying the equity method is measured as the aggregate of the carrying amounts of the assets and liabilities that the Corporation had previously proportionately consolidated. Such a change in accounting has affected the amounts reported in the Corporation's consolidated financial statements (see note 2.2).

Impact of the application of IFRS 12

IFRS 12 is a disclosure standard and is applicable to entities that have interests in subsidiaries, joint arrangements, associates and/or unconsolidated structured entities. The application of IFRS 12 has resulted in more extensive disclosures appearing in notes 10, 29 and 30.

IFRS 13, Fair Value Measurement

IFRS 13, Fair Value Measurement, replaces the fair value measurement guidance currently dispersed across different IFRS standards with a single definition of fair value and a comprehensive framework for measuring fair value when such measurement is required under other IFRSs. It also establishes disclosure requirements about fair value measurements. These standards have been adopted and applied in these consolidated financial statements. The application of these standards has not had any impact on the amounts reported for the current or prior year.

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

2.2 Additional IFRS information

2.2.1 Impact on the consolidated statement of earnings for the year ended December 31, 2012 of the application of IFRS 11

	Year ended December 31, 2012			
	As previously reported	IFRS 11 adjustments	As restated	
Revenues	180,860	(4,205)	176,655	
Expenses	,	(, ,	,	
Operating	29,133	(283)	28,850	
General and administrative	9,732	(131)	9,601	
Prospective projects	4,412	<u> </u>	4,412	
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	137,583	(3,791)	133,792	
Finance costs	63,281	(1,243)	62,038	
Other net expenses	15,527	39	15,566	
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on derivative financial instruments	58,775	(2,587)	56,188	
Depreciation	43,902	(1,300)	42,602	
Amortization	21,835	(672)	21,163	
Share of earnings of joint ventures	_	(1,166)	(1,166)	
Unrealized net gain on derivative financial instruments	(8,342)	551	(7,791)	
Earnings before income taxes	1,380	_	1,380	
Provision for income taxes :				
Current	1,970	_	1,970	
Deferred	4,793	_	4,793	
	6,763	-	6,763	
Net loss	(5,383)		(5,383)	
Net loss attributable to:				
Owners of the parent	1,405	_	1,405	
Non-controlling interests	(6,788)	<u> </u>	(6,788)	
	(5,383)	_	(5,383)	

There has been no impact from the application of IFRS 11 to the consolidated statement of comprehensive income (loss).

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

2.2.2 Impact on the consolidated financial position as at December 31, 2012 of the application of IFRS 11

	As previously reported	IFRS 11 adjustments	As restated
Assets			
Current assets			
Cash and cash equivalents	52,048	(2,552)	49,496
Restricted cash and short-term investments	87,811	_	87,811
Accounts receivable	50,786	(724)	50,062
Reserve accounts	1,816	_	1,816
Income tax receivable	443	_	443
Derivative financial instruments	2,116	(423)	1,693
Loans to related parties	23,444	_	23,444
Prepaid and others	4,789	(74)	4,715
	223,253	(3,773)	219,480
Reserve accounts	46,933	(1,133)	45,800
Property, plant and equipment	1,453,944	(26,832)	1,427,112
Intangible assets	440,498	(11,074)	429,424
Project development costs	107,165	(3,636)	103,529
Investments in joint ventures	_	18,935	18,935
Derivative financial instruments	6,698	_	6,698
Deferred tax assets	5,846	_	5,846
Goodwill	8,269	_	8,269
Other long-term assets	31,347	_	31,347
	2,323,953	(27,513)	2,296,440

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

2.2.2 Impact on the consolidated financial position as at December 31, 2012 of the application of IFRS 11 (continued)

	As previously reported	IFRS 11 adjustments	As restated
Liabilities			
Current liabilities			
Dividends payable to shareholders	14,643	_	14,643
Accounts payable and other payables	41,337	(85)	41,252
Income tax liabilities	1,541	_	1,541
Derivative financial instruments	17,855	(656)	17,199
Current portion of long-term debt	64,452	(526)	63,926
	139,828	(1,267)	138,561
Construction holdbacks	1,668	_	1,668
Derivative financial instruments	64,023	(3,215)	60,808
Accrual for acquisition of long-term assets	13,063	(164)	12,899
Long-term debt	1,189,649	(22,867)	1,166,782
Other liabilities	8,870	(==,00.)	8,870
Liability portion of convertible debentures	79,655	_	79,655
Deferred tax liabilities	139,265	_	139,265
	1,636,021	(27,513)	1,608,508
Shareholders' equity			
Common share capital	120,500	_	120,500
Contributed surplus from reduction of	,		·
capital on common shares	656,281	_	656,281
Preferred shares	131,069	_	131,069
Share-based payment	1,511	_	1,511
Equity portion of convertible debentures	1,340	_	1,340
Deficit	(330,621)	_	(330,621)
Accumulated other comprehensive income	241	_	241
Equity attributable to owners	580,321	_	580,321
Non-controlling interests	107,611	_	107,611
Total shareholders' equity	687,932	_	687,932
	2,323,953	(27,513)	2,296,440

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

2.2.3 Impact on the consolidated financial position as at January 1, 2012 of the application of IFRS 11

	As previously reported	IFRS 11 adjustments	As restated
Assets			
Current assets			
Cash and cash equivalents	35,279	(416)	34,863
Restricted cash and short-term investments	53,415	_	53,415
Accounts receivable	36,894	(336)	36,558
Income tax receivable	1,664	_	1,664
Derivative financial instruments	1,791	_	1,791
Prepaid and others	4,074	(97)	3,977
	133,117	(849)	132,268
Reserve accounts	42,154	(915)	41,239
Property, plant and equipment	1,259,834	(28,124)	1,231,710
Intangible assets	441,262	(11,750)	429,512
Project development costs	98,042	(801)	97,241
Investments in joint ventures	_	14,499	14,499
Derivative financial instruments	8,248	_	8,248
Deferred tax assets	24,485	_	24,485
Goodwill	8,269	_	8,269
Other long-term assets	17,998	_	17,998
	2,033,409	(27,940)	2,005,469

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

2.2.3 Impact on the consolidated financial position as at January 1, 2012 of the application of IFRS 11 (continued)

	As previously reported	IFRS 11 adjustments	As restated
Liabilities			
Current liabilities			
Dividends payable to shareholders	12,848	_	12,848
Accounts payable and other payables	26,616	(57)	26,559
Income tax liabilities	2,835	_	2,835
Derivative financial instruments	20,287	(1,227)	19,060
Current portion of long-term debt	19,475	(493)	18,982
Current portion of other liabilities	983		983
	83,044	(1,777)	81,267
Construction holdbacks	2,081	_	2,081
Derivative financial instruments	71,158	(2,772)	68,386
Accrual for acquisition of long-term assets	41,267		41,267
	1,030,037	(23,391)	1,006,646
Long-term debt Other liabilities	, ,	(23,391)	, ,
Liability portion of convertible debentures	6,762 79,490	_	6,762 79,490
Deferred tax liabilities	79,490 140,454	_	79,490 140,454
Deletted tax liabilities	1,454,293	(27,940)	1,426,353
	1,404,200	(21,040)	1,420,000
Shareholders' equity			
Common share capital	1	_	1
Contributed surplus from reduction of capital on common shares	656.281	_	656,281
Preferred shares	82,589	_	82,589
Share-based payment	1,361	_	1,361
Equity portion of convertible debentures	1,340	_	1,340
Deficit	(277,083)	_	(277,083)
Accumulated other comprehensive income	228	_	228
Equity attributable to owners	464,717	_	464,717
Non-controlling interests	114,399	_	114,399
Total shareholders' equity	579,116	_	579,116
	2,033,409	(27,940)	2,005,469

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

2.2.4 Impact on the consolidated statement of cash flows for the year ended December 31, 2012 of the application of IFRS 11

	As previously reported	IFRS 11 adjustments	As restated
Net cash inflow from operating activities	62,181	(1,274)	60,907
Net cash inflow from financing activities	312,379	494	312,873
Net cash outflow from investing activities	(357,755)	(1,356)	(359,111)
Effects of exchange rate changes on cash and cash equivalents	(36)	_	(36)
Net increase in cash and cash equivalents	16,769	(2,136)	14,633

2.3 New IFRS issued but not yet effective

IFRS 9 - Financial instrument

As part of the project to replace IAS 39, Financial Instruments: Recognition and Measurement, this standard retains but simplifies the mixed measurement model and establishes two primary measurement categories for financial assets. More specifically, the standard:

- Deals with classification and measurement of financial assets;
- Establishes two primary measurement categories for financial assets: amortized cost and fair value;
- Prescribes that classification depends on entity's business model and the contractual cash flow characteristics
 of the financial asset;
- Eliminates the existing categories: held-to-maturity, available-for-sales, and loans and receivables.

Certain changes were also made regarding the fair value option for financial liabilities and accounting for certain derivatives linked to unquoted equity instruments.

In July 2013, the International Accounting Standards Board ("IASB") decided to temporarily defer the mandatory effective date of IFRS 9 and to not specify that date until the requirement for financial instrument classification and measurement and financial asset impairment are finalized. The Corporation is monitoring the progress of the IASB's work.

IFRIC 21 - Levies

In May 2013, the 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. IFRIC 21 is effective for annual periods commencing on or after January 1, 2014. The Corporation is currently evaluating the impact the final interpretation is expected to have on its consolidated financial statements.

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

3. SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

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

Investments in joint ventures

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

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

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

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

The Corporation discontinues the use of the equity method from the date when the investment ceases to be a joint venture. When the Corporation retains an interest in the former joint venture and the retained interest is a financial asset, the Corporation measures the retained interest at fair value at that date and the fair value is regarded as its fair value on initial recognition in accordance with IAS 39. The difference between the carrying amount of the joint venture at the date the equity method was discontinued, and the fair value of any retained interest and any proceeds from disposing of a part interest in the joint venture is included in the determination of the gain or loss on disposal of the joint venture. In addition, the Corporation accounts for all amounts previously recognized in other comprehensive income in relation to that joint venture on the same basis as would be required if that joint venture had directly disposed of the related assets or liabilities. Therefore, if a gain or loss previously recognized in other comprehensive income by that joint venture would be reclassified to profit or loss on the disposal of the related assets or liabilities, the Corporation reclassifies the gain or loss from equity to profit or loss (as a reclassification adjustment) when the equity method is discontinued.

Investments in joint operations

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

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

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

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

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

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

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

Business combinations

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

Cash and cash equivalents

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

Restricted cash and short-term investments

The Corporation holds restricted cash and short-term investments designed to help ensure its stability.

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

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

Reserve accounts

The Corporation holds two types of reserve accounts designed to help ensure its stability. The first is the hydrology/wind reserve established at the start of commercial operations of a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind conditions or other unpredictable events. The amounts in the reserve are expected to vary from quarter to quarter according to the seasonality of cash flows. The second is the major maintenance reserve established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity.

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

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

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

Property, plant and equipment

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

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

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

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

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

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

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

The useful life used to calculate depreciation is as follows:

Type of property, plant and equipment	Ending years of depreciation period	Useful life for the depreciation period
Hydroelectric facilities	2019 to 2088	15 to 75 years
Wind farm facilities	2021 to 2037	15 to 25 years
Solar facility	2037	25 years
Other equipments	2014 to 2019	3 to 10 years

Leases

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

Intangible assets

Intangible assets consist of various permits, licenses and agreements. Intangibles assets are amortized using the straight-line method over a period ending on the maturity date of the permits, licenses or agreements of each facility. They are recorded at cost less accumulated amortization and accumulated impairment losses. Amortization starts when the related facility becomes ready for its intended use.

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

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

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

As of July 1, 2013, the Corporation changed the useful life for the amortization period for the intangible assets related to certain Quebec hydroelectric facilities. The estimated useful life, which was formerly equal to the first term of the respective Power Purchase Agreements ("PPAs") was increased by 20 to 25 years, which reflects the PPA's renewable rights periods. This change in accounting estimate arose from the Corporation's intention to exercice its option to renew its PPAs. This change in estimate was recorded prospectively. The estimated annual impact of this change in accounting estimate is a decrease of approximately \$3,595 in annual amortization expense for the next 12 months and will be declining in future periods. The impact of this change for the period ended December 31, 2013 is a \$1,830 decrease in amortization expense.

The useful life used to calculate amortization is as follows:

Intangible assets related to:	Ending years of amortization period	Useful life for the amortization period
Hydroelectric facilities	2016 to 2082	4 to 69 years
Wind farm facilities	2026 to 2028	19 to 20 years
Solar facility	2032	20 years
Extended warranties for wind turbines	2016 to 2017	3 years

Project development costs

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

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

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

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

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

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

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

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

Goodwill

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

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

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

Other long-term assets

Other long-term assets include a \$25,000 deposit plus accumulated interests of \$2,517 for the acquisition of any of Hydroméga's facilities, security deposits under various agreements and long-term receivables.

Accrual for acquisition of long-term assets

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

Provisions and asset retirement obligations

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

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

Financial instruments

Financial assets and liabilities are initially recorded at fair value and their subsequent measurement is dependent on their classification as described below. The classification depends on the purpose for which the financial instruments were purchased or issued, their characteristics and their designation by the Corporation.

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

All financial instruments are classified into one of the five categories: fair value through profit and loss, loans and receivables, other financial liabilities, held-to-maturity or available-for-sale.

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to available-for-sale financial assets, held-to-maturity financial assets, other financial liabilities and loans and receivables are added to the carrying value of the asset or are netted against the carrying value of the liability and are then recognized over the expected life of the instrument using the effective interest method.

The Corporation has made the following classification:

- Derivative financial instruments were classified as held for trading and thus are measured at fair value through profit and loss.
- Investment income earned on assets or liabilities designated as held for trading is included in other net (revenues)
 expenses in the consolidated statements of earnings.
- Net gains or losses on assets or liabilities classified as held for trading are included into net gain on derivative financial instruments in the consolidated statements of earnings. These net gains or losses do not include any investment income.
- Cash and cash equivalents, restricted cash and short-term investments, cash and cash equivalents included in reserve
 accounts, accounts receivable, loans to related parties and deposit for the acquisition of any of Hydroméga's facility
 are classified as loans and receivables and are measured at amortized cost, using effective interest rate method.
- Short-term investments and government-backed securities included in reserve accounts are classified as assets held-to-maturity and recorded at amortized cost, using effective interest rate method.
- Dividends payable to shareholders, accounts payable and other payables, construction holdbacks, accrual for acquisition of long-term assets, long-term debt, other liabilities and liability portion of convertible debentures are classified as other financial liabilities and are recorded at amortized cost, using effective interest rate method.
- The Corporation does not hold any available-for-sale financial assets.

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

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

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

The financial assets or liabilities measured at fair value are the derivative financial instruments which are level 3 for PPAs inflation provision and level 2 for interest rate swap, bond forward contracts.

Non-controlling interests

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

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

Hedging relationships

Derivative financial instruments are utilized by the Corporation to manage its interest rate exposure on debt financing. The Corporation's policy is not to utilize derivative financial instruments for trading or speculative purposes.

Derivatives used as economic hedges that do not qualify for hedge accounting are recognized on the consolidated statement of financial position at fair value and changes in fair value are recorded in earnings. The Corporation does not use hedge accounting for its derivative financial instruments.

Revenue recognition

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

Government assistance

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

The Corporation is entitled to subsidies under the EcoEnergy program. The subsidies are equal to 1¢ per KWh produced at the Ashlu Creek, Fitzsimmons Creek, Douglas Creek, Fire Creek, Stokke Creek, Tipella Creek, Lamont Creek, Upper Stave River, Magpie Limited Partneship and Umbata Falls hydro facilities and at the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms for the first 10 years following commissioning of each facility. As per the electricity purchase agreements, the Corporation must transfer 75% of the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms subsidies to Hydro-Québec. Gross EcoEnergy subsidies of \$12,463 (\$12,194 in 2012) are included in the revenues and the 75% payable to Hydro-Québec for the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms are included in the operating expenses.

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

Share-based payment

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

Foreign currency translation

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

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

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

The Corporation designates a portion of its U.S. dollar-denominated debt to hedge its investment in its U.S. functional currency foreign operations. Translation gains or losses on the portion of the debt designated as a hedge are included in other comprehensive income with the cumulative gain or loss reported in accumulated other comprehensive income. The gain or loss relating to the portion of the debt in excess of the investment in the foreign subsidiaries is recognized immediately in earnings. Gains and losses on the hedging instrument relating to the effective portion of the hedge accumulated in the foreign currency translation reserve are reclassified to earnings in the same way as exchange differences relating to the foreign operations. The Corporation formally documents this hedge. On a quarterly basis, the Corporation reviews the hedge to ensure that it effectively offsets the translation gains or losses arising from its investment in its U.S. functional currency foreign operation.

Income taxes

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

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

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

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

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

Earnings per share

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

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

4. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

Significant estimates and assumptions

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

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

Critical judgments and estimates

Fair Value of Financial Instruments

Certain financial instruments, such as derivative financial instruments, are carried in the consolidated statements of financial position at fair value, with changes in fair value reflected in earnings. Fair values of some financial instruments are estimated by using valuation techniques using several assumptions such as interest rate, credit spread and risk.

Useful Lives of Property, Plant and Equipment and Intangible assets

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

Goodwill Impairment

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

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

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

Business acquisition fair value

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

Structured entity

Based on the contractual arrangements between the Corporation and the other partner, the Corporation concluded that it has control over Kwoiek Creek Resources L.P.

Income Taxes

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

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

5. BUSINESS ACQUISITIONS

5.1 Acquisition of Magpie Limited Partnership

On July 25, 2013, the Corporation finalized the acquisition of 99.999% of the common units of the Magpie run-of-river hydroelectric facility located in Québec (the "Magpie Acquisition"). The Minganie Regional County Municipality holds 30% of the voting units as well as a convertible debenture and a non-interest bearing debenture. The convertible debenture entitles the municipality to a 30% interest in the facility upon conversion of the debenture at or before January 1, 2025. The Corporation has paid cash the purchase price of \$28,577.

All power generated from the facility is sold to Hydro Québec under a PPA expiring in 2032.

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 Magpie facility added an additional installed capacity of approximately 40.6 MW to the Corporation's portfolio of operational hydroelectric facilities.

The following table reflects the preliminary purchase price allocation:

Cash and cash equivalents	1,885
Accounts receivable	1,321
Prepaid and others	52
Reserve account	422
Property, plant and equipment	74,460
Intangible assets	30,413
Current liabilities	(1,203)
Long-term debt	(66,024)
Other long-term liabilities	(2,428)
Deferred tax liabilities	(10,320)
Non-controlling interests	(1)
Net assets acquired	28,577

The preliminary 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, 2013, the consolidated revenues and net earnings for the year ended December 31, 2013 would have been \$203,323 and \$45,786.

The amounts of revenues and net earnings of Magpie Limited Partnership since July 25, 2013 included in the consolidated statement of earnings are \$5,489 and \$1,835 respectively for the 160 days ended December 31, 2013.

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

5.2 Acquisition of Brown Miller Power L.P.

The valuation of the acquisition of Brown Miller Power L.P. has been finalized. The following table reflects the final purchase price allocation:

	Preliminary purchase price allocation	Subsequent Adjustments	Final purchase price allocation
Accounts receivable	429	_	429
Prepaid and others	153	-	153
Property, plant and equipment	64,391	(14,732)	49,659
Intangible assets	13,436	14,732	28,168
Current liabilities	(9)	_	(9)
Deferred tax liabilities	(9,765)	_	(9,765)
	68,635	_	68,635

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Corporation holds interest rate swap contracts and bond forwards contracts ("Interest hedging instruments") that enable it to eliminate its exposure to the floating interest rates payable on the portion of its long-term debt, which is hedged by such contracts. The counterparties to the contracts are major financial institutions; the Corporation does not anticipate any payment defaults on their part. The estimated impact of an increase in swap rates curve of 0.1% would increase the fair value of these financial instruments by \$10,323. Conversely, a decrease in swap rates curve of 0.1% would result in a decrease of \$10,522 of the fair value of these financial instruments.

The Corporation records embedded derivatives separately from the host contracts ("Inflation provisions"). These financial instruments relate to provisions establishing minimum inflation rate at 3% of the selling prices provided for under some of the PPAs entered into with Hydro-Québec. The Corporation does not anticipate any payment defaults from the counterparty. The fair value of these financial instruments is evaluated using revenue estimates based on long-term production averages estimated for each facility. It varies based on the difference between the 3% minimum inflation rate and the long-term inflation rate, which is estimated at 2% as at December 31, 2013 over the remaining terms of these agreements, discounted at a rate of 3.21%. The expected impact of a 0.1% increase in the long-term inflation rate would reduce the fair value of these financial instruments by \$653; a 0.1% decrease in the long-term inflation rate would increase the fair value of these financial instruments by \$650.

The classification of the fair value hierarchy of all the financial assets and liabilities remained the same during 2013.

Financial assets (liabilities)	Interests hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2013 (restated)	(78,007)	8,391	(69,616)
Variation in fair value of derivative financial instruments	43,733	(1,743)	41,990
Settlements	3,259	_	3,259
Unrealized net gain (loss) on derivative financial instruments	46,992	(1,743)	45,249
As at December 31, 2013	(31,015)	6,648	(24,367)

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

Financial assets (liabilities)	Interests hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
			(restated)
As at January 1, 2012	(87,446)	10,039	(77,407)
Variation in fair value of derivative financial instruments	(4,688)	(1,648)	(6,336)
Settlements	14,127	_	14,127
Unrealized net gain (loss) on derivative financial instruments	9,439	(1,648)	7,791
As at December 31, 2012	(78,007)	8,391	(69,616)

Reported in the financial statements:

As at	December 31, 2013	December 31, 2012
		(restated)
Current assets – derivative financial instruments	7,563	1,693
Long-term asset – derivative financial instruments	7,066	6,698
Current liability – derivative financial instruments	(12,915)	(17,199)
Long-term liability – derivative financial instruments	(26,081)	(60,808)
	(24,367)	(69,616)

Interest rate risk

The terms of the contracts reducing the Corporation's risk of interest rate fluctuations are as follows:

			Notional Amounts	
Contract	Maturity	Early termination option	December 31, 2013	December 31, 2012
				(restated)
Bond forwards, from 3.04% to 3.27% (1.93% to 2.38% in 2012)	2014	None	340,000	40,000
Interest rate swaps, from 3.96% to 4.09%	2015	None	15,000	15,000
Interest rate swap, 4.27%	2016	None	3,000	3,000
Interest rate swaps, 4.27% to 4.41%	2018	None	82,600	82,600
Interest rate swaps, 2.94% to 4.83%, amortizing	2026	None	52,539	43,514
Interest rate swaps, from 3.35% to 3.60%, amortizing	2027	None	39,807	42,792
Interest rate swap, 3.74%, amortizing	2030	None	97,723	101,780
Interest rate swap, 4.22%, amortizing	2030	2016	28,803	30,021
Interest rate swap, 4.25%, amortizing	2031	2016	45,417	47,323
Interest rate swap, 4.61%, amortizing	2035	2025	102,818	105,031
Interest rate swap, 2.85%, amortizing	2041	2016	19,591	19,853
			827,298	530,914

The Corporation entered into hedge agreements to mitigate the risk of fluctuations in the interest rates on its long-term debt. Rates on contracts represent the interest rate, excluding the applicable margin.

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

7. OPERATING EXPENSES

	Year ended [Year ended December 31		
	2013	2012		
		(restated)		
Salaries	2,851	2,665		
Insurance	2,119	1,768		
Operation and maintenance	16,367	13,209		
Property taxes and royalties	12,610	11,208		
	33,947	28,850		

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

8. FINANCE COSTS

	Year ended December 31	
	2013	2012
		(restated)
Interest on long-term debt and on convertible debentures	59,823	55,971
Inflation compensation interest	1,892	3,362
Amortization of financing fees	902	729
Amortization of revaluation of long-term debt and convertible debentures	1,955	1,526
Accretion expenses on other liabilities	546	450
Others	40	_
	65,158	62,038

9. OTHER NET (REVENUES) EXPENSES

	Year ended l	Year ended December 31		
	2013	2012		
		(restated)		
Transaction costs	609	2,766		
Realized loss on derivative financial instruments	3,259	14,127		
Realized loss (gain) on foreign exchange	369	(82)		
Gain on contingent considerations	(19)	(357)		
Other net revenues	(2,832)	(1,118)		
Loan impairment	_	1,000		
Compensation from contractor	_	(770)		
Write-off of project development costs	222	_		
Settlement of claims received in relation with an acquisition	(2,000)	_		
	(392)	15,566		

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

10. INVESTMENTS IN JOINT VENTURES

10.1 Details of material joint ventures

Details of the Corporation's material joint ventures at the end of the reporting period are as follows:

Name of joint venture	Principal activity	Place of creation and principal place of operation	Proportion of ow and voting righ Corpo	
			December 31, 2013	December 31, 2012
Umbata Falls, L.P.	Own and operate an hydroelectric facility	Ontario	49%	49%
Viger-Denonville, L.P.	Own and operate a wind farm	Québec	50%	50%

The joint ventures are accounted for using the equity method in these consolidated financial statements.

Summarized financial information in respect of the Corporation's material joint ventures is set out below. The summarized financial information below represents amounts shown in the joint venture's financial statements prepared in accordance with IFRSs.

Umbata Falls, L.P.

Summary Statements of Financial Position

As at	December 31, 2013	December 31, 2012	January 1, 2012
Cash and cash equivalents	1,738	1,254	73
Other current assets	1,947	1,547	822
Current assets	3,685	2,801	895
Non-current assets	75,864	79,679	83,244
Accounts payable and other payables	133	155	66
Other current liabilities	47,839	2,227	3,512
Current liabilities	47,972	2,382	3,578
Non-current liabilities	1,852	53,225	53,394
Shareholder's equity	29,725	26,873	27,167

Summary Statements of Earnings and Comprehensive Income

	Year ended December 31		
	2013	2012	
Revenues	12,073	8,581	
Operating, general and administrative expenses	746	835	
	11,327	7,746	
Finance costs	2,501	2,536	
Other net revenues	(34)	(20)	
Depreciation and amortization	4,024	4,025	
Unrealized net gain on derivative financial instruments	(4,694)	(448)	
Net earnings and comprehensive income	9,530	1,653	

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

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	December 31, 2013	December 31, 2012	January 1, 2012
Net assets of the joint venture	29,725	26,873	27,167
Proportion of the Corporation's ownership interest in the joint venture	49%	49%	49%
Carrying amount of the Corporation's interest in the joint venture	14,565	13,167	13,311

Umbata Falls, L.P. 's Debt

The loan consists of a five-year term loan, amortized over a 25-year period starting in July 2009. The term loan bears interest at BA rate plus an applicable margin. The term loan is repayable in quarterly instalments. It is expected that the loan of \$46,665 maturing in July 2014, included in other current liabilities, will be refinanced.

The lender also agreed to make available a letter of credit facility in a principal amount not exceeding \$500. As at December 31, 2013, an amount of \$470 has been used to secure two letters of credit. This debt is secured by all of Umbata Falls LP's assets with a carrying value of approximately \$79,500.

Viger-Denonville, L.P.

Summary Statements of Financial Position

As at	December 31, 2013	December 31, 2012	January 1, 2012
Cash and cash equivalents	1,787	3,875	762
Other current assets	7,434	916	59
Current assets	9,221	4,791	821
Non-current assets	63,940	7,274	1,603
Accounts payable and other payables	183	17	48
Other current liabilities	8,017	183	_
Current liabilities	8,200	200	48
Non-current liabilities	44,813	328	_
Shareholder's equity	20,148	11,537	2,376

Summary Statements of Earnings and Comprehensive Income

	Year ended December 31		
	2013	2012	
Revenues	1,295	_	
Operating, general and administrative expenses	131	9	
	1,164	(9)	
Finance costs	231	_	
Other net revenues	(3,720)	(59)	
Depreciation and amortization	369	_	
Unrealized net loss (gain) on derivative financial instruments	1,517	(663)	
Net earnings and comprehensive income	2,767	713	

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

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	December 31, 2013	December 31, 2012	January 1, 2012
Net assets of the joint venture	20,148	11,537	2,376
Proportion of the Corporation's ownership interest in the joint venture	50%	50%	50%
Carrying amount of the Corporation's interest in the joint venture	10,074	5,768	1,188

Viger-Denonville, L.P. 's Debt

On August 7, 2013, Viger-Denonville, L.P. closed a \$61,700 non-recourse construction and term project financing. Following the start of the project's commercial operation, it will convert into an 18-year term loan. As at December 31, 2013, the term loan carries a floating interest rate equal to the banker's acceptance rate plus an applicable margin for an all-in rate of 3.82%. Viger-Denonville, L.P. has also closed a short-term loan of \$5,490 carrying a floating interest rate at banker's acceptance rate plus an applicable margin for an all-in rate of 3.22% as at December 31, 2013 to finance the construction of the substation and collector system, for which it is entitled to be reimbursed by Hydro-Québec in 2014. The lenders also agreed to make available a letter of credit facility in an amount not to exceed \$984. As at December 31, 2013, an amount of \$984 has been used to secure one letter of credit. These loans are secured by Viger-Denonville, L.P's assets with a carrying value of approximately \$73,200.

Concurrent with the closing of the financing, Viger-Denonville, L.P. has settled the bond forward contracts used to hedge the interest rate on the debt and therefore protect the expected returns on the project, giving rise to a realized gain on derivative financial instruments of \$2,226 and partly offsetting the higher interest-rate on the project debt. Viger-Denonville, L.P. entered into an interest rate swap of \$58,520, maturing in 2031 and bearing an interest rate of 3.40%.

10.2 Commitments of joint ventures

As at December 31, 2013, the expected schedule of commitment payments for Umbata Falls, L.P. and Viger-Denonville, L.P. is as follows:

Years of	Hydroelectric Generation	Wind Power Generation	Total
2014	23,760	4,813	28,573
2015	613	2,200	2,813
2016	396	2,191	2,587
2017	232	2,135	2,367
2018	108	2,106	2,214
Thereafter	122	28,660	28,782
Total	25,231	42,105	67,336

Umbata Falls, L.P.

25 years after the beginning of the operations, the partnership will be dissolved. Upon the dissolution of the partnership, the property and assets of the partnership shall be transferred to the other partner for no consideration.

Viger-Denonville, L.P.

Parc Eolien Communautaire Viger-Denonville LP entered into royalties and other commitments related to amounts to set aside for the dismantling of wind farm components, commitments to surrounding municipalities and the operation of the wind farms.

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

11. KEY MANAGEMENT PERSONNEL COMPENSATION

The following are the expenses that the Corporation recognized for its key management personnel. The members of the Board of Directors as well as the President and all the Vice-Presidents are key management personnel of the Corporation.

	Year ended I	Year ended December 31			
	2013	2012			
Salaries and short-term benefits	3,940	3,936			
Attendance fees for members of the Board of Directors	566	578			
Termination benefits	39	227			
Performance share plan	678	767			
Share-based payment	295	298			
	5,518	5,806			

12. EMPLOYEE BENEFITS

The expenses that the Corporation recognized for its employee benefits is composed of salaries and short-term benefits. The expenses were included in the following categories:

	Year ended De	Year ended December 31		
	2013	2012		
		(restated)		
Operating expenses	2,851	2,665		
General and administrative	7,919	5,339		
Prospective projects expenses	1,631	2,147		
Transaction costs	609	1,059		
Capitalized in Property, plant and equipment	2,769	3,737		
Capitalized in Project development costs	2,552	1,693		
	18,331	16,640		

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

13. INCOME TAXES

a. Income tax recognized in profit or loss

	December 31, 2013	December 31, 2012
Current tax		
Current tax expense in respect of the current year	2,639	2,039
Adjustments recognized in the current year in relation to the current tax expense of prior years	(21)	(69)
	2,618	1,970
Deferred tax		
Deferred tax expense recognized in the current year	16,003	121
Increase in deferred income tax rates	1,226	_
Increase in deferred income tax rates due to internal reorganization	_	2,113
Change in recognized taxable temporary differences on a subsidiary with a non-controlling interest	_	1,999
Adjustments recognized in the current year in relation to the deferred tax of prior years	1,014	560
	18,243	4,793
Total income tax expense recognized in the current year to continuing operations	20,861	6,763

The total income tax expense for the year can be reconciled to the accounting profit as follows:

	December 31, 2013	December 31, 2012
Earnings before income taxes	66,292	1,380
Canadian statutory income tax rate	26.5%	26.0%
Income tax expense calculated at the statutory rate	17,567	359
Items affecting the statutory rate:		
Non-deductible expenses	473	780
Recognition of tax losses	(520)	(227)
Income taxable at a different rate than the Canadian statutory tax rate	_	134
Increase in deferred income tax rates	1,226	_
Increase in deferred income tax rates due to internal reorganization	_	2,113
Change in recognized taxable temporary differences on a subsidiary with a non-controlling interest	_	1,999
Increase in taxable temporary differences in relation to investments in subsidiaries and in joint ventures	1,262	577
Income tax on dividends on preferred shares	171	94
Adjustments recognized in the current year in relation to the current tax of prior years	(21)	(69)
Adjustments recognized in the current year in relation to the deferred tax of prior years	1,014	560
Adjustments related to changes in legislation	(1,260)	_
Income tax on loss allocated to minority interests on non-taxable entities	943	408
Others	6	35
Income tax recognized in profit or loss relating to continuing operations	20,861	6,763

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

The tax rate used for 2013 and 2012 reconciliations above is the average combined corporate tax rate payable by corporate entities in Canada on taxable profits under federal and provincials' tax laws. The British-Columbia tax rate increased on April 1st, 2013 from 10% to 11%.

b. Income tax recognized in other comprehensive income

	December 31, 2013	December 31, 2012
Deferred tax		
Arising on income and expenses recognized in other comprehensive income:		
Translation of self-sustaining foreign subsidiaries	46	(12)
Designated portion of the US dollar denominated debt used as a hedge on the investments in self-sustaining foreign subsidiaries	(45)	13
Total income tax recognized directly in other comprehensive income	1	1

c. Income tax recognized directly in equity

	December 31, 2013	December 31, 2012
Deferred tax		
Arising on transactions with owners:		
Share issue expenses deductible over 5 years	_	(2,864)
Total income tax recognized directly in equity	_	(2,864)

d. Current tax assets and liabilities

	December 31, 2013	December 31, 2012
Current tax assets		
Benefit of tax losses to be carried back to recover taxes paid in prior periods	_	440
Tax refund receivable	80	3
	80	443
Current tax liabilities		
Income tax payable	2,216	1,541

e. Deferred tax balances

The following is the analysis of deferred tax assets (liabilities) presented in the consolidated statements of financial position:

	December 31, 2013	December 31, 2012
Deferred tax assets	1,804	5,846
Deferred tax liabilities	(163,689)	(139,265)
	(161,885)	(133,419)

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

	As at January 1, 2013	Recognized in profit or loss	Recognized in other comprehensive income	Acquisitions/ disposals	Recognized directly in equity	Net exchange differences	As at December 31, 2013
Deferred tax assets (liabilities) in relation to:							
Property, plant and equipment	(67,345)	(13,041)	_	(5,729)	_	75	(86,040)
Intangible assets	(81,738)	(4,035)	_	(7,748)	_	(34)	(93,555)
Project development costs	(24,529)	11,813	_	_	_	_	(12,716)
Investments into subsidiaries and in joint ventures	(420)	(206)	(46)	_	_	_	(672)
Non-repatriated income from foreign subsidiaries	(513)	(168)	_	_	_	_	(681)
Derivative financial instruments	26,396	(11,624)	_	_	_	_	14,772
Long-term debt	(8,554)	358	_	2,521	_	_	(5,675)
Convertible debentures	(217)	42	_	_	_	_	(175)
Other liabilities	_	13	_	636	_	_	649
Financing fees	3,085	(1,887)	_	_	_	_	1,198
	(153,835)	(18,735)	(46)	(10,320)	_	41	(182,895)
Tax losses and minimum taxes	20,416	492	45	_	_	57	21,010
	(133,419)	(18,243)	(1)	(10,320)		98	(161,885)

As at December 31, 2013, the Corporation, its subsidiaries and joint ventures have non-capital losses totaling approximately \$82,000 that may be applied against future taxable income. These non-capital losses expire gradually between 2027 and 2033.

The Corporation recognized a deferred tax asset on non-capital losses because it is probable that taxable profit will be available against which the deductible temporary difference can be utilized.

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

	As at January 1, 2012	Recognized in profit or loss	Recognized in other comprehensive income	Acquisitions/ disposals	Recognized directly in equity	Net exchange differences	As at December 31, 2012
Deferred tax assets (liabilities) in relation to:							
Property, plant and equipment	(62,441)	2,399	_	(7,275)	_	(28)	(67,345)
Intangible assets	(75,290)	1,738	_	(8,201)	_	15	(81,738)
Project development costs	(8,589)	(15,940)	_	_		_	(24,529)
Investments into subsidiaries and in joint ventures	(2,910)	2,478	12	_	_	_	(420)
Non-repatriated income from foreign subsidiaries	(399)	(114)	_	_	_	_	(513)
Derivative financial instruments	24,875	1,521	_	_	_	_	26,396
Long-term debt	(8,425)	(129)	_	_	_	_	(8,554)
Convertible debentures	(262)	45	_	_	_	_	(217)
Financing fees	4,109	(3,888)	_	_	2,864	_	3,085
	(129,332)	(11,890)	12	(15,476)	2,864	(13)	(153,835)
Tax losses and minimum taxes	13,363	7,097	(13)	_	_	(31)	20,416
	(115,969)	(4,793)	(1)	(15,476)	2,864	(44)	(133,419)

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

f. Unrecognized deductible temporary differences, unused tax losses and unused tax credits

	December 31, 2013	December 31, 2012
Tax losses - revenue in nature	8,079	4,284
Tax losses- capital in nature	569	569
Transaction costs	2,842	3,095
	11,490	7,948

The unrecognized tax losses-revenue in nature will expire gradually between 2029 and 2031.

14. COMPUTATION OF EARNINGS AVAILABLE TO COMMON SHAREHOLDERS

The net earnings attributable to owners of the parent are adjusted for the dividends on the Preferred shares as follows:

	Year ended December 31		
	2013	2012	
Net earnings attributable to owners of the parent	48,170	1,405	
Dividends declared on Preferred Shares	(7,391)	(4,250)	
Net earnings (loss) available to common shareholders	40,779	(2,845)	
Weighted average number of common shares (in 000s)	94,694	86,557	
Basic net earnings (loss) per share (\$)	0.43	(0.03)	
Weighted average number of common shares (in 000s)	94,694	86,557	
Effect of dilutive elements on common shares (in 000s) (a)	86	151	
Diluted weighted average number of common shares (in 000s)	94,780	86,708	
Diluted net earnings (loss) per share (\$) (b)	0.43	(0.03)	

- **a.** During the year ended December 31, 2013, 2,013,420 of 3,073,684 stock options (1,263,000 of 2,736,684 as at December 31, 2012) and 7,558,684 shares which can be issued on conversion of convertible debentures (7,558,684 as at December 31, 2012) 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 year ended December 31, 2012, 1,473,684 stock options were excluded from the calculation of diluted net loss per share as it was anti-dilutive due to a net loss available to common shareholders.

15. RESTRICTED CASH AND SHORT-TERM INVESTMENTS

As at	December 31, 2013	December 31, 2012
Restricted cash accounts	19,975	7,676
Restricted proceeds account	23,115	73,539
Debt service payment accounts	6,655	6,596
	49,745	87,811

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

As part of the Kwoiek Creek LP and Northwest Stave credit agreements, the Corporation maintains restricted cash accounts and restricted proceeds accounts. The balance of the loans proceeds are held in a restricted proceeds account managed by Kwoiek Creek and Northwest Stave lenders and amounts are transferred from time to time into the restricted cash accounts to finance the construction of the Kwoiek Creek Project and Northwest Stave Project. The restricted cash accounts are used to pay the current construction costs of the Kwoiek Creek Project and Northwest Stave Project and to hold the construction holdbacks amounts that will be released at the end of the construction of the project.

In relation with the six run-of-river hydroelectric facilities at Harrison Hydro L.P. (the "Harrison Operating Facilities"), the Corporation maintains debt service payment accounts. The debt service payment accounts require a monthly transfer equal to one-sixth of the next semi-annual bond payments and a monthly transfer equal to one-third of the next quarterly bond payment required on the outstanding junior bonds. Senior and junior loan payments are taken from this account on their due dates.

16. ACCOUNTS RECEIVABLE

As at	December 31, 2013	December 31, 2012	
		(restated)	
Trade	14,787	18,458	
Commodity taxes	1,595	10,243	
Investment tax credits	1,898	1,487	
Payment receivable for property, plant and equipment	_	15,257	
Others	1,519	4,617	
	19,799	50,062	

Substantially all of the Corporation's trade receivables relate to electricity sold to public utilities including Hydro-Québec, British Columbia Hydro, Hydro One Inc. and its affiliates and Idaho Power Company. Hydro-Québec currently holds a credit rating of A+ from Standard & Poor's (S&P). British Columbia Hydro and Power Authority currently holds a credit rating of AAA from S&P. The Ministry of Energy of the Province of Ontario has stated that the Province of Ontario, which currently holds a credit rating of AA- from S&P, will honor Hydro One Inc. and its affiliates obligations under the PPAs to which it is a party. Hydro One Inc. and its affiliates currently holds a credit rating of BBB from S&P.

Commodity taxes and investment tax credits are receivable from the federal or provincial governments, following the development and construction of projects. The payment receivable for property, plant and equipment was also receivable from Hydro-Québec and was related to the Gros Morne wind farm.

The Corporation did not record any allowance for doubtful accounts since, based on its experience, there is a low risk of bad debts. The Corporation does not hold any specific guarantees for its accounts receivable. All accounts receivable are current.

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

17. RESERVE ACCOUNTS

			December 31, 2013
	Hydrology / wind power reserve	Major maintenance reserve	Total
Reserves – As at January 1, 2013 (restated)	45,291	2,325	47,616
Reserve acquired on business acquisition (Note 5.1)	_	422	422
Net (withdrawals) investments in the reserves	(1,362)	835	(527)
Impact of foreign exchange fluctuations	43	8	51
Reserves – end of year	43,972	3,590	47,562
Less:			
Current portion	(1,771)	_	(1,771)
Long-term portion	42,201	3,590	45,791

			December 31, 2012
	Hydrology / wind power reserve	Major maintenance reserve	Total
			(restated)
Reserves – As at January 1, 2012	38,357	2,882	41,239
Net investments (withdrawals) in the reserves	6,948	(557)	6,391
Impact of foreign exchange fluctuations	(14)	_	(14)
Reserves – end of year	45,291	2,325	47,616
Less:			
Current portion	(1,816)	_	(1,816)
Long-term portion	43,475	2,325	45,800

During the year, the amounts held in the hydrology/wind power reserve generated investment income of \$395 (\$276 in 2012).

During the year, the amounts held in the major maintenance reserve generated investment income of \$27 (\$21 in 2012).

Reserve account investments	Maturity	Market value	Net carrying value
Government-backed securities	2014	664	664
Short-term investments	2014	16,005	16,005
Cash and cash equivalents		30,893	30,893
		47,562	47,562

The market value of the government-backed securities is determined by referring directly to the published active market prices. Short-term investments are held at major financial institutions. The Corporation recorded no impairment of these financial instruments since the counterparties have high credit ratings.

The availability of \$42,797 (\$41,408 in 2012) in the reserve accounts is restricted by credit agreements.

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

18. PROPERTY, PLANT AND EQUIPMENT

	Land	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2013 (restated)	2,105	920,368	370,819	124,133	140,901	6,127	1,564,453
Additions	30	6,945	1,213	100	87,926	1,453	97,667
Business acquisitions (Note 5)	_	59,606	_		_	122	59,728
Transfer of assets upon commissioning	_	75,177	_		(75,177)	_	_
Transfer from projects under development	_	_	_		47,565	32	47,597
Dispositions	_	_	(99)	_	_	(240)	(339)
Other changes	_	605	(1,204)	(28)	527	(29)	(129)
Net foreign exchange differences	6	364	_	_	_	8	378
As at December 31, 2013	2,141	1,063,065	370,729	124,205	201,742	7,473	1,769,355
Accumulated depreciation							
As at January 1, 2013 (restated)	_	(83,609)	(47,255)	(3,965)	_	(2,512)	(137,341)
Depreciation	_	(23,815)	(17,517)	(5,950)	_	(1,392)	(48,674)
Dispositions	_	_	_	_	_	156	156
Other changes	_	2	_	_	_	29	31
Net foreign exchange differences	_	(107)	_	_	_	(3)	(110)
As at December 31, 2013	_	(107,529)	(64,772)	(9,915)	_	(3,722)	(185,938)
Net value as at December 31, 2013	2,141	955,536	305,957	114,290	201,742	3,751	1,583,417

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 year include \$13,359 of capitalized financing costs (\$5,104 in 2012) 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 (\$472 as at December 31, 2012).

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

	Land	Hydroelectric facilities	Wind Farm facilities	Solar Facility	Facilities under construction	Other equipment	Total
							(restated)
Cost							
As at January 1, 2012	1,887	855,830	303,101	_	161,239	4,577	1,326,634
Additions	_	604	2,709	129	167,678	1,771	172,891
Business acquisition (Note 5)	220	64,112	_	_	_	59	64,391
Transfer of assets upon commissioning	_	_	64,036	123,980	(188,016)	_	_
Dispositions	_	(63)	_	_	_	(277)	(340)
Other changes	_	_	973	24	_	_	997
Net foreign exchange differences	(2)	(115)	_	_	_	(3)	(120)
As at December 31, 2012	2,105	920,368	370,819	124,133	140,901	6,127	1,564,453
Accumulated depreciation							
As at January 1, 2012	_	(61,551)	(31,918)	_	_	(1,455)	(94,924)
Depreciation	_	(22,094)	(15,337)	(3,965)	_	(1,206)	(42,602)
Dispositions	_	8	_	_	_	149	157
Net foreign exchange differences	_	28	_	_	_	_	28
As at December 31, 2012		(83,609)	(47,255)	(3,965)	_	(2,512)	(137,341)
Net value as at December 31, 2012	2,105	836,759	323,564	120,168	140,901	3,615	1,427,112

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

19. INTANGIBLE ASSETS

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
Cost					
As at January 1, 2013 (restated)	426,334	81,582	9,538	7,195	524,649
Additions	_	_	_	_	_
Business acquisitions (Note 5)	45,145	_	_	_	45,145
Transfer of assets upon commissioning	7,000	_	_	(7,000)	_
Transfer from projects under development	_	_	_	12,111	12,111
Other changes	5	_	_	(191)	(186)
Net exchange differences	135	_	_	_	135
As at December 31, 2013	478,619	81,582	9,538	12,115	581,854
Accumulated amortization					
As at January 1, 2013 (restated)	(74,924)	(20,003)	(298)	_	(95,225)
Amortization	(15,552)	(4,457)	(477)	_	(20,486)
Other changes	(5)	_	_	_	(5)
Net exchange differences	(45)	_	_	_	(45)
As at December 31, 2013	(90,526)	(24,460)	(775)		(115,761)
Net value as at					
December 31, 2013	388,093	57,122	8,763	12,115	466,093

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
					(restated)
Cost					
As at January 1, 2012	406,904	80,144	_	16,538	503,586
Additions	6,038	1,438	_	195	7,671
Business acquisitions (Note 5)	13,436	_	_	_	13,436
Transfer of assets upon commissioning	_	_	9,538	(9,538)	_
Net exchange differences	(44)	_	_	_	(44)
As at December 31, 2012	426,334	81,582	9,538	7,195	524,649
Accumulated amortization					
As at January 1, 2012	(58,994)	(15,080)	_	_	(74,074)
Amortization	(15,942)	(4,923)	(298)	_	(21,163)
Net exchange differences	12	_	_	_	12
As at December 31, 2012	(74,924)	(20,003)	(298)		(95,225)
Net value as at					
December 31, 2012	351,410	61,579	9,240	7,195	429,424

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

20. PROJECT DEVELOPMENT COSTS

	December 31, 2013	December 31, 2012
		(restated)
Cost		
Beginning of year	103,529	97,241
Additions	38,044	6,288
Transfer to property, plant and equipment	(47,597)	_
Transfer to intangible assets	(12,111)	_
Write-off of project development costs	(222)	_
End of year	81,643	103,529

For the years ended December 31, 2013 and 2012, the Corporation conducted annual project development costs impairment tests. Based on the result of these tests, no impairment charge was required.

The recoverable amount of the project development costs is determined based on a value in use calculation which uses cash flow projections based on comparatives projects financial budgets approved by management covering a period extending between 40 and 75 years and a pre-tax discount rate of 7.84% to 9.00% (9.92% in 2012).

Assumptions used to determine the recoverable amount of assets are the following:

- The discount rate is a weighted average between the consolidated cost of debt and the consolidated cost of equity to which a risk premium is added for each project.
- A cash-generating unit is an individual hydroelectric facility.
- The future expected cash flows are based on comparative projects budgets of each cash-generating unit. The budgets have been built using long-term averages of water flows. These long-term averages approximate actual results.
- The number of projects and the timing of projects to be developed.

Additions in the current year include \$622 of capitalized interests (\$304 in 2012).

21. GOODWILL

Allocation of goodwill to each cash-generating unit is as follows:

As at	December 31, 2013	December 31, 2012
St-Paulin	935	935
Portneuf	4,166	4,166
Chaudière	3,168	3,168
Total Goodwill	8,269	8,269

For the years ended December 31, 2013 and 2012, the Corporation conducted annual goodwill impairment tests. Based on the result of these tests, no impairment charge was required.

The recoverable amount of each cash-generating unit is determined based on a value in use calculation which uses cash flow projections based on financial budgets approved by management covering a period extending to the lesser of 50 years or the period for which the Corporation owns its rights on the site and a pre-tax discount rate of 6.84% (7.78% in 2012).

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

Assumptions used to determine the recoverable amount of assets are the following:

- The discount rate is a weighted average between the consolidated cost of debt and the consolidated cost of equity to which a risk premium is added for each cash-generating unit.
- A cash-generating unit is an individual hydroelectric facility.
- The future expected cash flows are based on the budgets before debt service and income tax of each cash-generating unit. The budgets have been built using long-term averages of water flows. These long-term averages approximate actual results.

22. ACCOUNTS PAYABLE AND OTHER PAYABLES

As at	December 31, 2013	December 31, 2012
		(restated)
Trade and others payables	32,750	24,273
Current portion of construction holdbacks	7,129	7,642
Interest payable	6,548	6,431
Commodity taxes	1,831	2,906
	48,258	41,252

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

23. LONG-TERM DEBT

As at	December 31, 2013	December 31, 2012
		(restated)
Revolving credit term facility (a)		
Prime rate advances renewable until 2018 (rate of 3.60%, 3.85% in 2012)	20	20
Bankers' acceptances renewable until 2018 (rate of 2.57%, rate of 3.04% in 2012)	170,480	189,780
LIBOR advances, US\$13,900 renewable until 2018 (rate of 1.54%, 2.10% in 2012)	14,784	13,829
Term loans		
Fitzsimmons Creek, floating-rate term loan maturing in 2016 (rate of 2.37%, same in 2012) (b)	21,791	22,133
Hydro-Windsor, 8.25% fixed rate term loan maturing in 2016 (c)	3,186	4,145
Montagne-Sèche, floating-rate term loan maturing in 2016 (rate of 3.72%, 3.73% in 2012) (d)	28,803	30,021
Magpie, 2.33% fixed rate bridge loan maturing in 2017(e)	1,156	_
Magpie, 5.30% fixed rate debenture maturing in 2017(e)	1,399	_
Rutherford Creek, 6.88% fixed rate term loan maturing in 2024 (f)	45,757	48,634
Ashlu Creek, floating-rate term loan maturing in 2025 (rate of 2.81%, 2.66% in 2012) (g)	98,822	100,810
Magpie, 6.16% fixed rate convertible debenture convertible in 2025 (e)	5,497	_
L'Anse-à-Valleau, floating-rate term loan maturing in 2026 (rate of 2.32%, 2.33% in 2012) (h)	41,188	43,515
Carleton, floating-rate term loan maturing in 2027 (rate of 3.28%, 2.72% in 2012) (i)	51,712	43,412
Stardale, floating-rate term loan maturing in 2030 (rate of 3.47%, 3.48% in 2012) (j)	106,220	110,630
Magpie, 4.37% fixed rate term loan maturing in 2031(e)	56,566	_
Kwoiek Creek, 14% fixed rate (k)	3,662	150
Kwoiek Creek, 5.08% fixed rate construction loan (k)	168,500	168,500
Northwest Stave River, 5.30% fixed rate construction loan (I)	71,972	_
Other loans with various maturities and interest rates	116	222
Bonds		
Harrison Operating Facilities, senior real return bond maturing in 2049 (rate of 3.97%, same in 2012) (m) (p)	223,049	225,137
Harrison Operating Facilities, 6.61% senior fixed rate bond maturing in 2049 (n) (p)	211,681	213,738
Harrison Operating Facilities, junior real return bond maturing in 2049 (rate of 5.04%, same in 2012) (o) (p)	27,031	26,760
	1,353,392	1,241,436
Deferred financing costs	(13,025)	(10,728)
	1,340,367	1,230,708
Current portion of long-term debt (net of nil deferred financing costs in 2013, \$33 in 2012)	(26,649)	(63,926)
Long-term portion	1,313,718	1,166,782

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

a. Revolving term credit facility

On June 17, 2013, the Corporation extended its \$425,000 revolving term credit facility with a new five year term ending in 2018. Terms and conditions remain unchanged and usage flexibility is enhanced.

As at December 31, 2013, a LIBOR rate advance of \$14,784 (US\$13,900) along with Bankers' Acceptances ("BA") rate advances and prime rate advances totaling \$170,500 were due under this facility. An amount of \$30,349 has been used to secure letters of credit. Thus, the unused and available position of the facility was \$209,367. The carrying value of assets of the Corporation and subsidiaries given as securities under this facility totals approximately \$694,500.

b. Fitzsimmons Creek

The loan consists of a five-year term loan, amortized over a 30-year period starting in December 2011. The loan advances bear interest at BA rate plus an applicable margin. The principal repayments are variable and are set to \$278 for 2014.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed \$150. As at December 31, 2013, an amount of \$150 has been used to secure two letters of credit. This debt is secured by all of Fitzsimmons Creek Hydro Limited Partnership assets with a carrying value of approximately \$25,600.

c. Hydro-Windsor

The loan consists of a 20-year term loan starting in December 1996 amortized over a 20-year period maturing in December 2016. The loan is repayable by monthly blended payments of principal and interest totaling \$105. The principal repayments for 2014 are set to \$960. The loan is secured by Hydro-Windsor LP's assets, with a carrying value of approximately \$11,200.

d. Montagne-Sèche

The loan consists of a four-year term loan, amortized over an 18.5-year period starting in March 2012. The loan bears interest at BA rate plus an applicable margin. The principal repayments are variable and set to \$1,318 for 2014.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed \$445. As at December 31, 2013, an amount of \$445 has been used to secure one letter of credit. The loan is secured by Innergex Montagne-Sèche, LP's assets with a carrying value of approximately \$40,600.

e. Magpie

As part of the Magpie Acquisition, the Corporation assumed a \$49,251 term loan, bearing interest at 6.36%, repayable in monthly blended payments of principal and interest totaling \$379 and maturing on December 1, 2031 and a \$1,188 bridge loan, bearing interest at 6.06%, repayable in monthly blended payments of principal and interest totaling \$27 and maturing on August 1, 2017. The term loan was accounted for at its fair market value of \$57,420 on the Magpie Acquisition for an effective rate of 4.37% and the bridge loan was accounted for at its fair market value of \$1,281 on the Magpie Acquisition for an effective rate of 2.33%.

The loans are repayable in monthly instalments. The principal repayments for the term loan are variable and are set at \$1,495 for 2014; the principal repayment for the bridge loan are set at \$271 for 2014. The loans are secured by Magpie LP's assets with a carrying value of approximately \$106,900.

As part of the Magpie Acquisition, the Corporation assumed a \$2,000 debenture, bearing no interest and repayable in yearly installments of \$400 and maturing on December 31, 2017. The debenture was accounted for at its fair market value of \$1,778 on the Magpie Acquisition for an effective rate of 5.30%.

As part of the Magpie Acquisition, the Corporation assumed a \$3,000 convertible debenture, bearing interest at 15.50%, maturing in 2025. The convertible debenture was accounted for at its fair market value of \$5,545 on the Magpie Acquisition for an effective rate of 6.16%. The convertible debenture entitles the municipality to a 30% interest in the facility upon conversion of the debenture on or before January 1, 2025. Early conversion is at the discretion of the Corporation.

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

f. Rutherford Creek

The loan consists of a 20-year fixed rate term loan starting in July 2004 amortized over a 12-year period effective July 1, 2012. This debt is repayable by monthly blended payments of principal and interest totaling \$511. The principal repayments for 2014 are set to \$3,081. The loan is secured by Rutherford Creek Power Limited Partnership's assets, with a carrying value of approximately \$86,500.

g. Ashlu Creek

The loan consists of a 15-year term loan, amortized over a 25-year period starting in September 2010. The loan bears interest at BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set to \$2,355 for 2014.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed \$3,000. As at December 31, 2013 an amount of \$1,595 has been used to secure one letter of credit. The loan is secured by Ashlu Creek hydroelectric facility's assets with a carrying value of approximately \$172,200.

h. L'Anse-à-Valleau

The loan consists of a 18.5-year term loan starting in December 2007 and amortized over a 18.5-year period. The loan bears interests at BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at \$2,472 for 2014.

The lenders also agreed to make available a credit facility of \$1,200 in order to secure letters of credit . As at December 31, 2013, an amount of \$423 has been used to secure one letter of credit. The loan is secured by Innergex AAV, LP's assets with a carrying value of approximately \$67,100.

i. Carleton

On June 26, 2013, the Corporation closed a \$52,800 non-recourse term loan to refinance its ownership portion of the Carleton wind farm. The loan consists of a 14-year term loan, amortized over a 14-year period which starts on June 26, 2013. The term loan bears interest at banker's acceptance rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at \$2,650 for the 2014.

This debt is secured by all Innergex CAR, LP's assets with a carrying value of approximately \$85,700.

j. Stardale

The loan consists of a 18-year term loan starting in September 2012 and amortized over an 18-year period. The term loan is repayable in quarterly installments. The principal repayments are variable and set to \$4,578 for 2014. The loan bears interest at the BA rate plus an applicable credit margin.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed \$5,600. As at December 31, 2013, an amount of \$5,600 has been used to secure two letters of credit. The loan is secured by Stardale L.P.'s assets with a carrying value of approximately \$128,000.

k. Kwoiek Creek

The partner of the Corporation in the Kwoiek Creek Project made a loan to Kwoiek Creek Resources Limited Partnership's. As per the agreements related to the project, both partners can participate in the financing of the project. The loans bear interests at a rate 14%. The partner's loan made to Kwoiek Creek Resources Limited Partnership amounts to \$3,662. The Corporation's loan made to Kwoiek Creek Resources Limited Partnership, which was eliminated in the financial statement consolidation process, amounts to \$55,471 as at December 31, 2013.

On July 17, 2012, Kwoiek Creek Resources Limited Partnership closed a \$168,500 non-recourse construction and term project financing for the Kwoiek Creek project. The loan carries a fixed interest rate of 5.08%; it will convert in a 39-year term loan following the start of the project's commercial operation and will be amortized over a 36-year period three years later. The loan is secured by Kwoiek Creek Resources L.P.'s assets with a carrying value of approximately \$190,900.

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

I. Northwest Stave River

On May 23, 2013, the Corporation closed a \$71,972 non-recourse construction and term project financing for the Northwest Stave River hydroelectric project. The construction loan carries a fixed interest rate of 5.30%; it will convert in a 40-year term loan following the start of the project's commercial operating and will be amortized over a 35-year period starting in the sixth year. The loan is secured by Northwest Stave River L.P.'s assets with a carrying value of approximately \$93,900.

m. Harrison Operating Facilities, Senior Real Return bond

The Harrison Operating Facilities Senior Real Return bond bears interest at 2.96% adjusted by an inflation ratio as well as an inflation compensation interest factor. Both inflation adjustments are based on the All-items Consumer Price Index for Canada ("CPI"), not seasonally adjusted. Payments on this bond are due semi-annually and the bond matures on June 1, 2049. Semi-annual payments were \$5,790 before CPI adjustment (\$6,382 including CPI adjustment in 2013). On December 1, 2031, the payment amount decreases to \$4,481 before CPI adjustment where it remains until maturity. For 2014, the principal repayments are set to \$5,244. The bond is secured by the Harrison Operating Facilities.

n. Harrison Operating Facilities, Senior Fixed Rate bond

The Harrison Operating Facilities Senior Fixed Rate bond bears interest at 6.61%. Payments on this bond are due semiannually with the bond maturing on September 1, 2049. Semi-annual payments amount to \$8,072. On September 1, 2031 the payment amount decreases to \$6,724 where it remains until maturity. For 2014, the principal repayments are set to \$2,937. The bond is secured by the Harrison Operating Facilities.

o. Harrison Operating Facilities, Junior Real Return bond

The Harrison Operating Facilities Junior Real Return Rate bond bears interest at 4.27% adjusted by an inflation ratio as well as an inflation compensation interest factor. Both inflation adjustments are based on the CPI, not seasonally adjusted. Payments on this bond are due quarterly and the bond matures on September 1, 2049. Quarterly interests payments amounted to \$291 before CPI adjustment (\$321 including CPI adjustment in 2013). On June 1, 2017 the payment amount increases to \$389 before CPI adjustment where it remains until maturity. Principal repayment does not commence until June 1, 2017. The bond is secured by the Harrison Operating Facilities.

p. Summary of Harrison Operating Facilities

The bonds are secured by the Harrison Operating Facilities. The carrying value of the property and assets of the Harrison Operating Facilities totals approximately \$674,000.

	Senior Real Return Bond	Senior Fixed Rate Bond	Junior Real Return Bond	Total
Balance – December 31, 2012	225,137	213,738	26,760	465,635
Inflation compensation interest	1,698	_	194	1,892
Principal repayment	(5,097)	(2,780)	_	(7,877)
Amortization of revaluation	1,311	722	77	2,110
Balance – December 31, 2013	223,049	211,680	27,031	461,760

The increase in inflation compensation interest is a result of the CPI rate change over the reference period.

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

Principal repayments

The principal repayments for the next years, excluding the revaluations, will be as follows:

	Principal repayments	Amortization of revaluation	Long-term debt
2014	28,061	(1,412)	26,649
2015	29,971	(1,469)	28,502
2016	74,769	(1,533)	73,236
2017	31,433	(1,575)	29,858
2018	218,427	(1,540)	216,887
Thereafter	1,023,081	(44,821)	978,260
	1,405,742	(52,350)	1,353,392

24. OTHER LIABILITIES

Other liabilities, including amounts shown in current liabilities, consist of contingent considerations and asset retirement obligations relating to the Corporation's facilities.

	Contingent considerations	Asset retirement obligations	Total
As at January 1, 2013	2,775	6,095	8,870
Liability assumed as part of the business acquisition (note 5.1)	2,428	_	2,428
Accretion expense included in finance cost	280	266	546
Gain on contingent considerations	(19)	_	(19)
Revisions in estimated cash flows	_	(896)	(896)
As at December 31, 2013	5,464	5,465	10,929
Current portion of other liabilities	(362)	_	(362)
Long-term portion of other liabilities	5,102	5,465	10,567

	Contingent considerations	Asset retirement obligations	Total
			(restated)
As at January 1, 2012	3,887	3,858	7,745
Liability recovered	(357)	_	(357)
Contingent considerations paid	(983)	_	(983)
Accretion expense included in finance cost	228	222	450
New obligations	_	1,018	1,018
Revision in estimated cash flows	_	997	997
As at December 31, 2012	2,775	6,095	8,870

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

a. Contingent considerations

An acquisition realized in 2011 provides for the potential payment of additional amounts to the vendors over a period commencing on the acquisition date and ending on the 40th anniversary of the last project under development to achieve commercial operation (or to April 4, 2061 if earlier). The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. The maximum aggregate amount of all deferred payments under this acquisition is limited to a present value amount of \$35,000 as at the acquisition date.

In connection with another acquisition, the Corporation agreed to pay contingent considerations based upon future events for a period of three years after April 20, 2011. These contingent considerations provide for the sharing of the potential value created if the project benefits from a better return than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. No maximum applies to the potential sharing.

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

b. Asset retirement obligations

Asset retirement obligations primarily arise from obligations to retire wind farms and solar facility upon expiry of the site leases. The wind farm facilities and solar facility were constructed on sites held under leases expiring 25 years after the signing date. The Corporation estimates that the undiscounted value of the payments required for settling the obligations over a 25-year period will be as follows:

Year of expected payments	
2031	2,592
2032	2,466
2033	2,748
2036	1,542
2037	6,243
	15,591

The cash flows were discounted at rates between 4.81% to 5.30% as at December 31, 2013 (4.11% to 4.62% in 2012) to determine the obligations.

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

25. CONVERTIBLE DEBENTURES

The convertible debentures bear interest at an annual rate of 5.75% and will mature on April 30, 2017. Interest is payable semi-annually on April 30 and October 31, of each year. Each convertible debenture is convertible into common shares of the Corporation at the option of the holder at any time prior to the earlier of April 30, 2017 and the redemption date specified by the Corporation. The conversion price is \$10.65 per common share (the "Conversion Price"), being a conversion rate of approximately 93.8967 common shares per each thousand of dollars of principal amount of convertible debentures. Holders converting their convertible debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their convertible debentures to the date of conversion.

Since April 30, 2013, and prior to April 30, 2015, the convertible debentures may be redeemed by the Corporation. Such redemption would be done, provided that the trading price of the common shares on the Toronto Stock Exchange is not less than 125% of the Conversion Price. On or after April 30, 2015 and prior to April 30, 2017, the convertible debentures may be redeemed at the option of the Corporation at a price equal to their principal amount. Subject to required regulatory approval, the Corporation may, at its option, elect to satisfy its obligation to pay the principal amount of the convertible debentures on redemption or at maturity, in whole or in part, through the issuance of freely tradable common shares upon prior notice, by delivering that number of common shares obtained by dividing the principal amount of the convertible debentures by 95% of the current market price. Any accrued or unpaid interest will be paid in cash.

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

The liability portion is being accreted such that the liability at maturity will equal the face value less prior conversions if any.

	December 31, 2013	December 31, 2012
Liability portion of convertible debentures, at fixed rate, 5.75% (effective rate of 6.09%), maturing on April 30, 2017, with a face value of \$80,500	79.831	79.655
value of \$60,000	7 3,00 1	70,000
Equity portion of convertible debentures	1,340	1,340

26. SHAREHOLDERS' CAPITAL

Authorized

The authorized capital of the Corporation consists of an unlimited number of common shares and an unlimited number of preferred shares, non-voting, retractable and redeemable. This includes up to 3,400,000 Cumulative Rate Reset Preferred Shares, Series A (the "Series A Preferred Shares") and up to 3,400,000 Cumulative Floating Rate Preferred Shares, Series B (the "Series B Preferred Shares"). On December 11, 2012 the authorized capital was modified to include up to 2,000,000 Cumulative Redeemable Fixed Rate Preferred Shares, Series C (the "Series C Preferred Shares").

a) Common shares

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

b) Reduction of the stated capital account of the common shares

Special resolutions to approve the reduction of the legal stated capital account maintained in respect of the common shares of the Corporation, without any payment or distribution to the shareholders were adopted on May 14, 2013. This resulted in a decrease of \$128,201 of the shareholders' capital account and an increase of \$128,201 of the contributed surplus from reduction of capital on common shares account.

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

c) Preferred shares

Series A Preferred Shares

On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at \$25.00 per share for aggregate gross proceeds of \$85,000. For the initial five-year period to, but excluding January 15, 2016 (the "Initial Fixed Rate Period"), the holders of Series A Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to \$1.25 per share.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of the Series A Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series A Preferred Share, equal to the sum of the yield on a Government of Canada bond with a term to maturity of five years on the applicable fixed rate calculation date, plus 2.79%, applicable to such Subsequent Fixed Rate Period multiplied by \$25.00.

Each holder of Series A Preferred Shares will have the right, at its option, to convert all or any of its Series A Preferred Shares into the Series B Preferred Shares of the Corporation on the basis of one Series B Preferred Share for each Series A Preferred Share converted, subject to certain conditions, on January 15, 2016 and on January 15 every five years thereafter. The holders of Series B Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series B Preferred Share equal to the Treasury Bills rate for the preceding quarterly period, plus 2.79%, per annum determined on the 30th day prior to the first day of the applicable quarterly floating rate period multiplied by \$25.00.

The Series A Preferred Shares and the Series B Preferred Shares will not be redeemable by the Corporation prior to January 15, 2016.

Series C Preferred Shares

On December 11, 2012, the Corporation issued a total of 2,000,000 Series C Preferred Shares at \$25.00 per share for aggregate gross proceeds of \$50,000.

Holders of the Series C Preferred Shares will be entitled to receive, fixed cumulative preferential cash dividends as and when declared by the Corporation's Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to \$1.4375 per share.

The Series C Preferred Shares will not be redeemable by the Corporation prior to January 15, 2018. The Series C Preferred Shares do not have a fixed maturity date and are not redeemable at the option of the holders.

d) Share-based payment

Stock option and performance share plans

The Corporation has a stock option plan and performance share plan. The share-based payments expense is accounted under fair value method. In accordance with this method, the stock options and the performance shares are measured at the fair value of the equity instruments at the date of grant.

The Corporation has a stock option plan providing for the granting of options by the Board of Directors to employees, officers, directors and certain consultants of the Corporation and its subsidiaries to purchase common shares. Options granted under the stock option plan will have an exercise price of not less than the market price of the common shares at the date of grant of the option, calculated as the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

The maximum number of common shares of the Corporation available for issuance pursuant to options granted under the stock option plan is 4,064,123. Any common shares subject to an option that expires or terminates without having been fully exercised may be subject to a further option. The number of common shares issuable to non-executive directors of the Corporation under the stock option plan cannot at any time exceed 1% of the issued and outstanding common shares.

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

Options must be exercised during a period established by the Board of Directors, which may not be greater than 10 years after the date of grant. Options granted under the stock option plan vest in equal amounts on a yearly basis over a period of four to five years following the grant date.

On September 5, 2012, 57,904 stock options have been exercised, for an amount of \$507. Following this transaction, an amount of \$148 was reclassified from share based payment in equity to common share capital.

	December	· 31, 2013	December 31, 2012		
	Number of options (000's)	Weighted average exercise price (\$)	Number of options (000's)	Weighted average exercise price (\$)	
Outstanding - beginning of year	2,736	10.08	2,677	9.97	
Granted during the year	397	9.13	417	10.70	
Exercised during the year	_	_	(58)	8.75	
Canceled during the year	(60)	10.15	(300)	10.25	
Outstanding - end of year	3,073	9.95	2,736	10.08	
Options exercisable - end of year	1,728	10.22	1,314	10.37	

The following options were outstanding and exercisable as at December 31, 2013:

Year of granting	Number of options outstanding (000's)	Exercise price (\$)	Number of options exercisable (000's)	Year of maturity
2007	846	11.00	846	2017
2011	770	9.88	385	2018
2012	397	10.70	99	2019
2010	663	8.75	398	2020
2013	397	9.13	_	2020
	3,073		1,728	

The Corporation applies the fair value method of accounting for options granted to senior management, which is estimated using the Black-Scholes option-pricing model. Share-based payments are expensed and a credit is made to the share-based payment account in the equity of the Corporation to account for the options granted. The following assumptions were used to estimate the fair value of the options issued to grantees:

	December 31, 2013	December 31, 2012
Risk-free interest rate	1.36% to 2.74%	1.36% to 2.74%
Expected annual dividend per common share	\$0.58	\$0.58
Expected life of options	4.67 to 6 years	4.67 to 6 years
Expected volatility	18% to 35%	19% to 35%

For the purpose of compensation expense, stock-based compensation is amortized to expenses on a straight-line basis over the vesting period of a maximum of five years. The weighted average contractual life of the outstanding stock options is five years. Expected volatility is estimated by considering historic average share price volatility.

e) Dividend Reinvestment Plan ("DRIP")

On August 31, 2012, the Corporation implemented a DRIP for its shareholders, starting with the dividend paid on October 15, 2012. The plan allow eligible common shareholders the opportunity to reinvest a portion or all of the dividends they receive to purchase additional common shares of the Corporation, without paying fees such as brokerage commissions and service charges. Shares will either be purchased on the open market or issued from treasury.

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

27. DIVIDENDS

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

For the year ended D	December 31, 2013			
Record date	Payment date	Dividends per common share (\$)	Dividend per Preferred Series A share (\$)	Dividend per Preferred Series C share (\$)
12/31/2012	1/15/2013	0.1450	0.3125	_
3/28/2013	4/15/2013	0.1450	0.3125	0.492300
6/28/2013	7/15/2013	0.1450	0.3125	0.359375
9/30/2013	10/15/2013	0.1450	0.3125	0.359375
		0.5800	1.2500	1.211050

^{1.} This initial dividend payment was higher to reflect dividends accruing since the closing date of the Series C Preferred Share offering of December 11, 2012. The regular quarterly dividend amount is \$0.359375.

or the year ended [December 31, 2012			
Record date	Payment date	Dividends per common share (\$)	Dividend per Preferred Series A share (\$)	Dividend per Preferred Series C share (\$)
12/30/2011	1/16/2012	0.1450	0.3125	_
3/30/2012	4/16/2012	0.1450	0.3125	_
6/29/2012	7/16/2012	0.1450	0.3125	_
9/28/2012	10/15/2012	0.1450	0.3125	_
		0.5800	1.2500	_

28. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	December 31, 2013	December 31, 2012
		(restated)
Accounts receivable and income tax receivable	31,951	2,682
Prepaid and others	(318)	(1,495)
Accounts payable, other payables and income tax liabilities	(1,350)	(586)
	30,283	601

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

b. Additional information

	December 31, 2013	December 31, 2012
		(restated)
Interest paid (including \$13,268 capitalized interest (\$8,949 in 2012))	73,009	65,011
Non-cash transactions		
in unpaid property, plant and equipment	(6,532)	(14,937)
in unpaid development costs	10,245	785
in unpaid intangibles assets	(27)	27
in unpaid issuance costs of preferred shares	(353)	396
loans to related parties	(23,444)	_
variation in discounted rates in asset retirement obligations	(896)	997
in common shares issued through DRIP	(18,075)	(2,935)

29. SUBSIDIARIES

29.1 General information of subsidiaries

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

Name of subsidiaries	Principal activity	Place of creation and operation	Proportion of ownership interest ar voting rights held by the Corporation	
			As at December 31, 2013	As at December 31, 2012
Harrison Hydro L.P. and its 8 subsidiaries	Own and operate hydroelectric facilities	British Columbia	50.01%	50.01%
Creek Power Inc. and its 6 subsidiaries	Develop, construct, own and operate hydroelectric facilities	British Columbia	66.67%	66.67%
Kwoiek Creek Resources L.P. ¹	Construct, own and operate an hydroelectric facility	British Columbia	50.00%	50.00%
Ashlu Creek Investments, L.P.	Own and operate an hydroelectric facility	British Columbia	100.00%	100.00%
Innergex L.P.	Own and operate hydroelectric facilities	Québec	100.00%	100.00%
Innergex GM, L.P.	Own and operate a wind farm facility	Québec	100.00%	100.00%
Magpie Limited Partnership ²	Own and operate an hydroelectric facility	Québec	99.999%	— %
Stardale Solar L.P.	Own and operate a solar facility	Ontario	100.00%	100.00%

^{1.} The Corporation owns more than 50% of the economic interest in Kwoiek Creek Resources L.P.

^{2.} Minganie Regional County Municipality owns 30% of the voting rights

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

The Corporation has subsidiaries, the principal activities of which are summarized as follows:

Principal activity	Principal place of business	Number of subsidiaries		
		As at December 31, 2013	As at December 31, 2012	
Own or operate hydroelectric facilities	Québec	7	5	
Own or operate riyarocicotric racinties	Ontario	4	4	
	British Columbia	21	19	
	United States	1	1	
-		33	29	
Own or operate wind farm facilities	Québec	10	10	
Own or operate a solar facility	Ontario	2	2	
Develop or construct hydroelectric facilities	British Columbia	12	12	
Holdings and others	Québec	9	6	
	Ontario	3	2	
	British Columbia	8	8	
	United States	2	2	
	Nova Scotia	2	2	
		24	20	
		81	73	

29.2 Details of non-wholly-owned subsidiaries that have non-controlling interests

The table below shows details of non-wholly-owned subsidiaries of the Corporation:

Name of subsidiaries	Place of creation and operation	Proportion of ownership interests and voting rights held by non-controlling interests Earnings (loss) allocated Accumulated to non-controlling interests controlling in for the year ended (deficit		interests and voting rights held by non-		interests	
		December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Harrison Hydro L.P. and its 8 subsidiaries	British Columbia	49.99%	49.99%	(3,450)	(1,469)	87,959	114,853
Creek Power Inc. and its 6 subsidiaries	British Columbia	33.33%	33.33%	761	(1,167)	758	(3)
Kwoiek Creek Resources, L.P. (1)	British Columbia	50.00%	50.00%	(6)	(4,041)	(7,134)	(7,128)
Others	Various	Various	Various	(44)	(111)	(154)	(111)
				(2,739)	(6,788)	81,429	107,611

^{1.} The Corporation owns more than 50% of the economic interest in Kwoiek Creek Resources L.P.

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

Summarized financial information in respect of each of the Corporation's subsidiaries that has material non-controlling interests is set out below. The summarized financial information below represents amounts before intragroup eliminations.

Harrison Hydro L.P. and its eight subsidiaries

As at	December 31, 2013	December 31, 2012
Summary Statements of Financial Position		
Current assets	30,143	69,089
Non-current assets	662,749	680,279
Current liabilities	13,925	16,588
Non-current liabilities	460,511	459,221
Equity attributable to owners	130,497	158,706
Non-controlling interests	87,959	114,853

	Year ended December 31		
	2013	2012	
Summary Statements of Earnings and Comprehensive Loss			
Revenues	47,196	51,943	
Expenses	(55,397)	(55,860)	
Net loss and comprehensive loss	(8,201)	(3,917)	
Net loss and comprehensive loss attributable to:			
Owners of the parent	(4,751)	(2,448)	
Non-controlling interests	(3,450)	(1,469)	
	(8,201)	(3,917)	
Distributions paid to non-controlling interests	23,444		
Summary Statements of Cash Flows			
Net cash inflow from operating activities	13,908	19,804	
Net cash outflow from financing activities	(7,877)	(7,530)	
Net cash outflow from investing activities	(9,751)	(461)	
Net (decrease) increase in cash and cash equivalents	(3,720)	11,813	

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

Creek Power Inc. and its six subsidiaries

As at	December 31, 2013	December 31, 2012
Summary Statements of Financial Position		
Current assets	6,593	1,358
Non-current assets	67,349	40,010
Current liabilities	13,547	8,987
Non-current liabilities	69,534	43,852
Deficit attributable to owners	(9,897)	(11,468)
Non-controlling interest (deficit)	758	(3)

	Year ended December 31		
	2013	2012	
Summary Statements of Earnings and Comprehensive Income (loss)			
Revenues	2,346	2,340	
Expenses	(15)	(6,021)	
Net earnings (loss) and comprehensive income (loss)	2,331	(3,681)	
Net earnings (loss) and comprehensive income (loss) attributable to:			
Owners of the parent	1,570	(2,514)	
Non-controlling interest	761	(1,167)	
	2,331	(3,681)	
Summary Statements of Cash Flows			
Net cash inflow from operating activities	731	1,739	
Net cash inflow from financing activities	19,485	2,531	
Net cash outflow from investing activities	(20,661)	(4,085)	
Net (decrease) increase in cash and cash equivalents	(445)	185	

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

Kwoiek Creek Resources L.P.

As at	December 31, 2013	December 31, 2012
Summary Statements of Financial Position		
Current assets	34,019	88,502
Non-current assets	177,928	113,796
Current liabilities	23,694	17,529
Non-current liabilities	202,901	199,424
Deficit attributable to owners	(7,514)	(7,527)
Non-controlling interest deficit	(7,134)	(7,128)

	Year ended December 31	
	2013	2012
Summary Statements of Earnings and Comprehensive income (loss)		
Revenues	7	_
Expenses	_	(8,077)
Net earnings (loss) and comprehensive income (loss)	7	(8,077)
Net earnings (loss) and comprehensive income (loss) attributable to:		
Owners of the parent	13	(4,036)
Non-controlling interest	(6)	(4,041)
	7	(8,077)
Summary Statements of Cash Flows		
Net cash outflow from operating activities	(4,499)	(14,049)
Net cash inflow from financing activities	3,391	183,317
Net cash outflow from investing activities	(3,012)	(163,108)
Net (decrease) increase in cash and cash equivalents	(4,120)	6,160

29.3 Financial support to structured entity

Based on the contractual arrangements between the Corporation and the other partner, the Corporation concluded that it has control over Kwoiek Creek Resources L.P.

The Corporation is responsible for financing approximately 20% of the capital costs and has loaned such amount or invested in preferred units of Kwoiek Creek Resources L.P.

Kwoiek Creek Resources Inc., the other partner, can participate for an amount up to \$3,200, plus accrued interests for a total of \$3,662 of subordinated debt and preferred units.

The Corporation invested a total of \$46,253 in Kwoiek Creek Resources L.P., plus accrued interests for a total of \$55,471 of subordinated debt and preferred units. This investment provides the Corporation with revenues under the form of interests and preferred distributions.

Interests or distributions on the aggregate subordinated debt and preferred units will subsequently be payable annually subject to the availability of gross revenues. The interests or distributions on preferred units are payable before making any distributions on the common units.

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

30. JOINT OPERATIONS

Name of entities	Principal activity	Place of creation and operation	Proportion of ownership interest ar voting rights held by the Corporation	
			December 31, 2013	December 31, 2012
Innergex AAV, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex BDS, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex CAR, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex GM, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex MS, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Others	operate wind farm facilities	Quebec	38% to 50%	38% to 50%

^{(1).} Each of the Limited Partnership owns a 38% ownership interest in the assets, liabilities, revenues and expenses and 50% voting rights of the joint operations.

31. RELATED PARTY TRANSACTIONS

The Harrison Operating Facilities distributed \$13,600 in 2013 (\$46,900 in 2012). The funds were distributed in the form of non-interest bearing loans to the Corporation and its partners. The loans of \$6,798 (\$23,444 in 2012) were presented as loans to partners at year end. On January 1, 2014, the \$6,798 loans were reimbursed (same for the \$23,444 in June 2013) directly from distributions from the Harrison Operating Facilities and a corresponding decrease in non-controlling interests was recorded in 2014 with no impact to cash flows.

During 2013, loans were made to Viger-Denonville project until such time as the project-level financing was put in place or drawn. These loans bore interest at the same rate as the Corporation paid to its lenders on the revolving credit facility plus a margin. These loans were reimbursed prior to the end of 2013.

32. FINANCIAL INSTRUMENTS

a. Fair value disclosures

Fair value estimates are made at specific points in time using available information about the financial instrument in question. These estimates are subjective in nature and often cannot be determined precisely.

As at December 31, 2013, the Corporation determined that the carrying values of its current financial assets and liabilities approximated their fair values due to these instruments' short term maturity.

As at December 31, 2013 the Corporation determined that the carrying values of its short-term investments and government-backed securities included in reserve accounts approximated their fair values due to these instruments short-term maturity.

The carrying values of the floating rate long-term debts are approximately \$3,181 lower than their estimated fair values based on the swap interest curve on December 31, 2013, increased by a risk premium ranging from 0.01% to 1.68% for a total ranging from 1.25% to 5.08%. The carrying values of the fixed-rate debts, the bonds and the debentures are approximately \$41,687 lower than their estimated fair market values based on the swap interest curve on December 31, 2013, increased by a risk premium ranging from 0.22% to 3.49% for a total ranging from 1.50% to 7.11%.

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

b. Interest rate risk

The Corporation entered into hedge agreements to mitigate the risk of fluctuations in the interest rates on its long-term debt. The Corporation has entered into new bond forward contracts for a notional amount of \$340,000 maturing in 2014 at a weighted average rate of 3.18%, to manage its risk on the projects of Upper Lillooet River, Boulder, Tretheway Creek and Big Silver.

The interest hedging instruments and related risks are described in detail in Note 6.

c. Credit risk

Credit risk relates to the possibility that a loss may occur from a party's failure to comply with contractual requirements.

Cash and cash equivalents are mainly held at large Canadian financial institutions and, to a lesser degree, at major U.S. financial institutions.

The Corporation's accounts receivable and related risks are described in detail in Note 16.

The reserve accounts and related risks are described in detail in Note 17.

The financial derivatives and related risks are described in detail in Note 6.

d. Liquidity risk

Liquidity risk relates to the capacity of the Corporation to meet liabilities as they become due. Certain covenants of long-term borrowing contracts could prevent the Corporation from repatriating funds from certain subsidiaries.

Some interest rate hedging instruments have embedded early termination options that are exercisable only on their underlying debt's maturity date. The triggering of these options could pose a liquidity risk. Should the early termination option be triggered, a presumed realized loss would be offset by the savings realized on future interest expenses, as a negative swap value would be the result of an environment in which interest rates were lower than the rate embedded in the swap.

The Corporation has a positive working capital of \$19,057 as at December 31, 2013 (\$80,919 in 2012). If necessary, the Corporation can use its revolving credit term facility, as described in Note 23 a), of which \$209,367 was available as at December 31, 2013 (\$200,248 in 2012). In addition, in the event of lower revenue due to a decline in production or to a major equipment breakdown, the Corporation has available reserve accounts (as described in Note 17) and is covered by insurance plans. Accordingly, the Corporation believes its current working capital to be sufficient to meet all of its needs.

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

The following table presents the maturities of the financial liabilities:

	Less than 3 months	Between 3 months and 1 year	Between 1 year and 5 years
Dividends payable to shareholders	15,651		
Accounts payable and others payable	39,290	8,968	
Income tax liabilities	1,214	1,002	
Current portion of derivative financial instruments	3,515	9,400	
Current portion of long-term debt	6,228	20,421	
Current portion of other liabilities	112	250	
Construction holdbacks			1,347
Derivative financial instruments			27,282
Accrual for acquisition of long-term assets			9,855
Long-term debt			348,482
Other liabilities			2,721
Liability portion of convertible debentures			79,831
Total	66,010	40,041	469,518

e. Market risk

Market risk is related to fluctuations in the fair value or future cash flows of a financial instrument because of market price variations. Market risk includes foreign exchange and interest rate risks, described under separate headings, and other price risks.

The sale of electricity is made pursuant to long-term agreements where the offtakers are committed to take and pay for the total production, up to certain annual limits. The inflation clauses of the sale price of electricity are normally allowing the Corporation to cover its increase of variable operation expenses. The inflation clauses included in some of the electricity purchasing contracts with Hydro-Québec are limited to a maximum of 6% per year.

f. Foreign exchange risk

The foreign exchange risk relates to fluctuations in the U.S. dollar and Euro against the Canadian dollar.

The Corporation has subsidiaries in the United States for which the revenues, net of the expenses incurred, are repatriated to Canada. A portion of the Corporation's debts is denominated in U.S. dollars. Repatriated funds that are not used to service the U.S. dollar-denominated debt are converted into Canadian dollars at the exchange rate in effect on the conversion date. The Corporation's net risk is estimated to be \$16 for each 1% increase in the value of the Canadian dollar against the U.S. dollar. The Corporation uses a portion of its U.S. dollar-denominated debt to hedge its investment in its subsidiaries, as described in Note 3.

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

33. COMMITMENTS AND CONTINGENCIES

In addition to the commitments of the Joint Venture presented in note 10, the Corporation entered into the following transactions:

a. Power Purchase Agreements

Quebec facilities

Under PPAs with terms varying from 20 to 25 years and expiring between 2014 and 2032, Hydro-Québec agreed to purchase all of the electrical energy provided by the facilities and wind farms located in the Province of Quebec. Certain facilities have an agreed maximum quantity of electricity and a minimum quantity of electricity to deliver during each of the consecutive 12-month periods. All of the hydroelectric facilities, at the exception of Magpie facility, can renew their power purchase agreements for identical periods.

Total revenues from Hydro-Québec amounted to \$86,927 in 2013 (\$69,560 in 2012), representing 44% of the Corporation's revenues (39% in 2012). The Corporation is economically dependent on Hydro-Québec given the size of its revenues.

British Columbia facilities

Under PPAs with terms varying from 20 to 40 years and expiring between 2016 and 2054, British Columbia Hydro and Power Authority agreed to purchase all of the electrical energy provided by the facilities located in the Province of British-Columbia.

Total revenues from British Columbia Hydro and Power Authority amounted to \$72,338 in 2013 (\$73,842 in 2012) representing 36% of the Corporation's revenues (42% in 2012). The Corporation is economically dependent on British Columbia Hydro and Power Authority given the size of its revenues.

Ontario facilities

Under PPAs with terms varying from 20 to 30 years and expiring between 2025 and 2032, Hydro One inc. and its affiliates agreed to purchase all of the electrical energy provided by the facilities located in Ontario.

Total revenues from the Ontario facilities amounted to \$22,256 (\$15,880 in 2012) representing 11% of the Corporation's revenues (9% in 2012).

Idaho facility

Under a PPAs with a 35-year term and expiring in 2030, Idaho Power Company agreed to purchase all of the electricity provided by Horseshoe Bend Hydroelectric Corporation.

Total revenues from Idaho Power Company amounted to \$3,013 in 2013 (\$3,365 in 2012), representing 2% of the Corporation's revenues (2% in 2012).

b. Other Commitments

Wind farm facilities

The Corporation and its subsidiaries entered into royalties and other commitments related to amounts to set aside for the dismantling of wind farm components, commitments to surrounding municipalities and the operation of the wind farms

Subsidiaries and/or joint ventures are also committed under options on leases for projects under development.

Stardale Solar LP

Service agreement

Stardale Solar LP entered into a contract for the operations and maintenance of the solar farm.

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

Ashlu Creek facility

First Nation agreements

Pursuant to an agreement with Ashlu Creek Investments Limited Partnership, a First Nation is entitled to a royalty based on revenues of the Ashlu Creek Project since the beginning of operations. A First Nation is also entitled to an incremental share of gross revenues exceeding a yearly threshold of gross revenues set out in the agreement. The agreement also requires the assets of the Ashlu Creek Project to be transferred to a First Nation for a nominal price after 40 years of commercial operation.

Brown Miller facilities

Brown Miller Power L.P. has several royalties agreements based on a percentage of gross revenues or on production.

Big Silver Creek facility

Big Silver Creek Power L.P. entered into agreements with stakeholders for the construction of a power generating facility.

Kwoiek Creek facility

Construction contracts

Kwoiek Creek Resources LP entered into various contracts for the construction of an hydroelectric power-generating facility.

Royalty agreement

Kwoiek Creek Resources Limited Partnership entered into an agreement to pay to Kwoiek Creek Resources Inc. an annual royalty, which is based on a percentage of the gross revenues, less project costs, for the first 20 years after the date of commencement of commercial operations of the Kwoiek Creek Project and an increased royalty for the 20 years thereafter. For the first 20 years of the operating phase, the partnership will not pay any interest on its subordinated debt nor any distribution on the preferred units, which are owned by the Corporation or the other partner, unless the royalty has been paid.

Dissolution of the partnership

40 years after the beginning of the operations, Kwoiek Creek Resources Limited Partnership will be dissolved (unless otherwise dissolved at an earlier date). Upon the dissolution, the property and assets shall be distributed to the other partner.

Harrison Hydro L.P.

First Nations Agreements

The ownership of Douglas Creek Project L.P. and Tipella Creek Project L.P. will be transferred to a First Nation on the 60th anniversary of the commercial operation date for no financial consideration.

Harrison Hydro L.P. entered into an agreement with First Nations to pay annual royalties based on a percentage of the gross revenues starting after the date of commencement of commercial operations of the facilities. This percentage will increase every 20 years for the first 60 years. An additional royalty will be payable if the average price per megawatt hour is greater than an agreed amount.

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

Rutherford Creek facility

Rutherford L.P. agreed to make payments to the former owners, following the expiry of the Rutherford Creek PPA. This payment is based on the difference between the then selling price of electricity and the last selling price of electricity under the agreement, adjusted annually following the expiry of the agreement by 50% of the increase or decrease in the CPI over the previous 12 months. This amount will correspond to 35% of the gross revenues attributable to the difference for the 20-year period following the expiry of the power purchase agreement. It will accrue annually and be paid quarterly during the following year. After the 20-year period, that portion of the payment will correspond to 30% of the gross revenues attributable to the difference. This commitment is secured by the Rutherford L.P. facility but is subordinated to the \$45,757 term loan described in Note 23 f).

Upper Lillooet facility

Upper Lillooet River LP entered into several contracts for the construction of hydroelectric power-generating facility.

Boulder Creek facility

Boulder Creek LP entered into several contracts for the construction of hydroelectric power-generating facility.

Glen Miller facility

Lease agreement

Glen Miller Power, Limited Partnership entered into a 30-year lease agreement ending in December 2035 for the site that is in commercial operation. The lease has a 15-year extension option upon terms and conditions to be negotiated.

Glen Miller Power, Limited Partnership is committed to remit the facility to the lessor of the site, at the end of the lease agreement, for no consideration

North West Stave facility

Royalties

North West Stave River Hydro LP, entered into an agreement to pay a First Nation an annual royalty based on a percentage of the gross revenues starting after the date of commencement of commercial operations of the North West Stave project. This percentage will increase every 20 years for the first 60 years. An additional royalty will be payable if the average price per megawatt hour is greater than an agreed amount.

Tretheway facility

Tretheway Creek Power L.P. entered into agreements with stakeholders for the construction of a power generating facility.

Magpie facility

Magpie Limited Partnership has several royalties agreements based on gross revenues or on production.

Operating leases

The Corporation is engaged under long-term operating leases of premises which will expire between 2015 and 2018.

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

Summary of commitments

As at December 31, 2013, the expected schedule of commitment payments is as follows:

Year of expected payment	Hydroelectric Generation	Wind Power Generation	Solar Generation	Site Development	Total
2014	66,500	17,376	10,472	53,942	148,290
2015	66,156	17,851	10,409	42,719	137,135
2016	84,691	41,397	10,340	14,077	150,505
2017	63,913	12,960	10,036	89,734	176,643
2018	64,006	22,316	10,019	180,993	277,334
Thereafter	1,391,738	96,507	112,394	198,047	1,798,686
Total	1,737,004	208,407	163,670	579,512	2,688,593

The Corporation is subject to various claims that arise in the normal course of business. Management believes that adequate provisions have been made in the accounts where required. Although it is not possible to estimate the extent of potential costs and losses, if any, management believes that the ultimate resolution of such contingencies will not have an adverse effect on the financial position of the Corporation.

34. CAPITAL DISCLOSURES

The Corporation's strategy in managing its capital is: (i) to develop or acquire high-quality power production facilities that generate sustainable and stable cash flows, with the objective of achieving a high return on invested capital, and (ii) to distribute a stable dividend.

The Corporation seeks to achieve its objectives by:

- Maintaining the generating capacity and enhancing the operation of its hydroelectric facilities, wind farms and solar farm; and
- · Acquiring and developing new electricity-generating facilities.

The Corporation maintains its generating capacity by investing the necessary funds to maintain and continually upgrade its equipment. The Corporation also invests approximately \$1,100 on an annual basis in major maintenance reserve in order to fund any major maintenance of hydroelectric facilities, wind farms or solar farm which may be required to preserve the Corporation's generating capacity.

The Corporation determines the amount of capital required, and its allocation between debt and equity, for the acquisition and development of new electricity-generating facilities by considering the specific characteristics of stability and growth of each facility. This determination is made in order to distribute a stable dividend while maintaining an acceptable level of indebtedness.

The Corporation has a hydrology/wind power reserve. This reserve could be used in the event that the net available cash for any given year is less than expected, due to normal changes in hydrology or wind conditions or other unpredictable factors.

The Corporation's capital is composed of long-term debt, convertible debentures and shareholders' equity. Total capital amounts to \$2,086,133 at year end.

The Corporation uses equity primarily to finance the development of projects. The Corporation uses long-term debt to finance the construction of its facilities. The Corporation expects to finance 70% to 85% of its construction costs mostly through non-recourse long-term debt financing.

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

Future development and construction of new facilities, development of projects, expenses on prospective projects and other capital expenditures will be financed out of cash generated from the Corporation's operating facilities, borrowings and/or issuance of additional equity. To the extent that external sources of capital, including issuance of additional securities of the Corporation, become limited or unavailable, the Corporation's ability to make necessary capital investment to construct new or maintain existing project facilities will be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion.

Under the terms of the Revolving credit term facility described in Note 23 a), the Corporation needs to maintain, a leverage ratio and an interest coverage ratio. If the ratios are not met, the lender has the ability to recall the facility.

Regarding the respective non-recourse projects financing, some subsidiaries of the Corporation need to maintain minimum debt coverage ratios. If the ratios of a particular project financing are not met, the lenders could have the ability to recall the particular debt. Certain financial restrictive clauses could prevent the subsidiaries from making distributions to the Corporation.

All debt covenants are monitored on a regular basis by the Corporation. During the year, the Corporation and its subsidiaries met all the financial and non-financial conditions related to their credit agreements.

The Corporation's capital management objectives, policies and procedures are to ensure the stability and sustainability of the dividend payable to its shareholders and the development or acquisition of power production facilities. The objectives were identical in prior years.

35. SEGMENTED INFORMATION

Geographic segments

The Corporation owns interests in 23 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2013, revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled \$3,013 (\$3,365 in 2012), representing a contribution of 1.5% for the year ended December 31, 2013 (1.9% in 2012) to the Corporation's consolidated revenues for these periods.

Major Customers

A major customer is defined as an external customer whose transaction with the Corporation amount to 10% or more of the Corporation's annual revenues. The Corporation has identified three major customers whose sales are the following:

		Year ended December 31		
Major customer	Segment	2013	2012	
			(restated)	
British Columbia Hydro and Power authority	Hydroelectric generation	72,338	73,842	
Hydro-Québec	Hydroelectric and wind power generation	86,927	69,560	
Hydro One inc and its affiliates	Hydroelectric and solar generation	22,256	15,880	
		181,521	159,282	

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. Through its site development segment, it analyzes potential sites and develops hydroelectric, wind and solar facilities up to the commissioning stage.

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

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 loss (earnings) of joint ventures, 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.

The solar power generation segment was added following the beginning of commercial operation of the Stardale solar farm on May 15, 2012.

Year ended December 31, 2013					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	126,932	54,499	16,828	_	198,259
Expenses:					
Operating	22,849	9,939	1,159	_	33,947
General and administrative	7,373	2,140	317	1,364	11,194
Prospective projects				4,202	4,202
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net gain on derivative financial instruments	96,710	42,420	15,352	(5,566)	148,916
Finance costs					65,158
Other net revenues					(392)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on derivative financial instruments					84,150
Depreciation					48,674
Amortization					20,486
Share of earnings of joint ventures					(6,053)
Unrealized net gain on derivative financial instruments					(45,249)
Earnings before incomes taxes					66,292

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	240,372	116,085	405,112	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)

Year ended December 31, 2012					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Operating segments	generation	generation	generation	development	(restated)
Revenues	119,421	45,558	11,676	_	176,655
Expenses:	-,	.,	,-		.,
Operating	20,357	7,960	533	_	28,850
General and administrative	5,314	2,248	278	1,761	9,601
Prospective projects	_	_	_	4,412	4,412
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on derivative financial instruments	93,750	35,350	10,865	(6,173)	133,792
Finance costs					62,038
Other net expenses					15,566
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on derivative financial instruments					56,188
Depreciation					42,602
Amortization					21,163
Share of earnings of joint ventures					(1,166)
Unrealized net gain on derivative financial instruments					(7,791)
Earnings before income taxes					1,380

As at December 31, 2012					
					(restated)
Goodwill	8,269	_	_	_	8,269
Total assets	1,293,971	423,634	139,222	439,613	2,296,440
Total liabilities	807,661	290,913	127,393	382,541	1,608,508
Acquisition of property, plant and equipment during the					
year	64,936	2,709	129	169,508	237,282

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

36. SUBSEQUENT EVENTS

a. Dividends declared by the Board of Directors

Date of announcement	Record date	Payment date	Dividends per common share (\$)	Dividends per Series A Preferred Share (\$)	Dividends per Series C Preferred Share (\$)
02/25/2014	03/31/2014	04/15/2014	0.1500	0.3125	0.359375

b. Commissioning of the Kwoiek Creek Hydroelectric Facility

On February 18, 2014, the Corporation announced that the Kwoiek Creek Resources Limited Partnership has begun commercial operation of the Kwoiek Creek run-of-river hydroelectric facility located in British Columbia, Canada. Innergex holds 50% of Kwoiek Creek Resources Limited Partnership, and is responsible for the management of the construction and the operation of the facility. The Kanaka Bar Indian Band holds the remaining 50% interest. The 49.9 MW Kwoiek Creek hydroelectric facility is located partly on Crown lands and partly on reserve lands.

c. Commissioning of the Northwest Stave River Hydroelectric Facility

On February 24, 2014, the Corporation announced the commissioning of the Northwest Stave River run-of-river hydroelectric facility located in British Columbia, Canada. This facility is located on Crown land, approximately 50 km north of Mission, British Columbia.

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

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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

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