IN REVIEW

INNERGEX RENEWABLE ENERGY INC.'S ANNUAL REVIEW

INNERGEX

2012 ISSUE

INNERGEX

A YEAR IN THE WORLD OF
RENEWABLE ENERGY

July 20, 2012

Partnership with the Mi'gmaq Nation of Québec

The partnership agreement between Innergex and the Mi'gmawei Mawiomi (the Mi'gmaq Nation of Québec) calls for the development, financing, construction, and operation of a large wind farm on the Gaspé Peninsula of Québec.

IN REVIEW

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

FORWARD-LOOKING INFORMATION

In order to inform shareholders and potential investors about the Corporation's future prospects, this document may contain forward-looking information within the meaning of securities legislation ("Forward-Looking Information"). Forward-Looking Information can generally be identified by the use of words and phrases, such as "about", "approximate", "potential", "may", "will", "should", "estimate", "anticipate", "plans", "expects" or "does not expect", "is expected", "budget", "scheduled", "forecasts", "intends" or "believes", or variations of such words and phrases that state that certain events will occur. Such Forward-Looking Information includes, without limitation, statements with respect to the start or completion of the construction of any of the development projects, closing of the Magpie acquisition or of the other Hydromega assets. The Forward-Looking Information includes forward-looking financial information or financial outlook, within the meaning of securities laws, such as projected revenues, projected construction costs, or approximate purchase price to inform investors and shareholders of the potential financial impact of recently announced acquisitions or expected results; such information may not be appropriate for other purposes. Forward-Looking Information represents, as of the date of this document, the estimates, forecasts, projections, expectations, or opinions of the Corporation relating to future events or results. Forward-looking Information involves known and unknown risks, uncertainties and other important factors, which may cause the actual results or performance to be materially different from any future results or performance expressed or implied by the Forward Looking Information. The material risks and uncertainties which may cause the actual results and developments to be materially different from the current expressed expectations in this document include, without limitation: execution of strategy; capital resources; derivative financial instruments; availability of water flows, wind and sun light; delays and cost over-runs in the construction and design of projects; health, safety and environmental risks; development of new facilities; permits; project performance; equipment failure; interest rate and refinancing risk; financial leverage and restrictive covenants; declaration of dividends is at the discretion of the Board; securing new power purchase agreements; senior management and key employees; litigation; performance of major counterparties; relationship with stakeholders; equipment supply; regulatory and political; ability to secure appropriate land; reliance on power purchase agreements; reliance upon transmission systems; water rental expenses; assessment of water, wind and sun resources; dam safety; natural disasters; force majeure; foreign exchange; insurance limits; credit rating may not reflect actual performance of the Corporation; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired and to be acquired; failure to realize acquisition benefits; failure to close the Magpie hydroelectric facility acquisition and the other Hydromega hydroelectric facilities and development projects; shared transmission and interconnection facilities; introduction to solar photovoltaic power facility operation; revenues from the Miller Creek facility based on the spot price of electricity. Although the Corporation believes that the expectations instigated by the Forward-Looking Information are based on reasonable and valid hypotheses, there is a risk that the Forward-looking Information may be incorrect. The reader is cautioned not to rely unduly on this Forward-Looking Information. The Forward-Looking Information expressed verbally or in writing, by the Corporation or by a person acting on its behalf, is expressly qualified by this cautionary statement. The Forward-Looking Information contained herein is made as of the date of this document 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 required by legislation.

IN REVIEW 2012 ISSUE

July 26, 2012

Significant new shareholder

Innergex consolidates its long-standing relationship with the Caisse de dépôt et placement du Québec through a private placement of common shares of $100 million.

> *"Through this transaction, the Caisse is participating in the growth of a Québec leader that is extremely well positioned in renewable energy, a sector with a promising future."*
>
> – **Normand Provost,** Executive Vice President, Private Equity, CDPQ

October 4, 2012

Official inauguration of the Stardale solar farm

Innergex welcomes the Honourable Chris Bentley, Minister of Energy of the Government of Ontario and other distinguished guests to officially celebrate the commercial operation of its first solar farm.

October 15, 2012

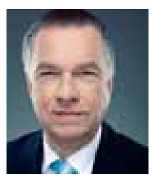
Acquisitions in British Columbia

Innergex completes the acquisition of the Brown Lake and Miller Creek hydro facilities with total installed capacity of 40 MW and long-term average annual production of 150 GWh.

December 5, 2012

Corporate Knights' Cleantech 10 List

For the second year in a row, Innergex is part of the Corporate Knights Cleantech 10 list. This list of Canadian public and private clean technology companies aims to recognize the innovation and hard work carried out by these organizations on the road to a greener and more productive economy.



Stability and secure growth

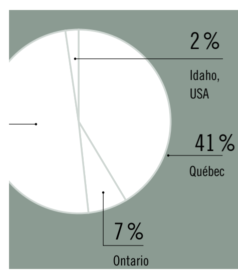
Jean La Couture, Chairman of the Board, summarizes the role and priorities of the Board of Directors of Innergex.

34

December 11, 2012

$50M of new capital

Innergex joins the ranks of a select group of companies to issue fixed-rate preferred shares, and becomes the first P-3 (S&P) rated company in Canada to do so.



Dashboard

- Financial and operational highlights
- Report card

AND MORE 36

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 the reader with additional information about its production and cash generation capabilities, and facilitate the comparison of results over different periods. Adjusted EBITDA is not a measure recognized by IFRS and has no standardized meaning prescribed by IFRS. References in this document to "Adjusted EBITDA" are to operating revenues less operating expenses, general and administrative expenses and prospective project expenses. Investors are cautioned that these non-IFRS measures should not be construed as an alternative to net earnings as determined in accordance with IFRS.

Journey to the heart of **renewable energies**

Innergex currently has 22 run-of-river hydroelectric facilities, including 11 in British Columbia, seven in Québec, three in Ontario, and one in the United States, with a total gross installed capacity of 408 MW. The company's roots trace back to the government-sponsored resurgence of small private hydroelectric facilities in Québec in the early 1990s. Hydro remains Innergex's primary and preferred source of renewable energy; it represented 73% of the electricity generated by Innergex in 2012. The company remains very active in the hydroelectric sector and continues to advance its ambitious development program of no less than six hydroelectric projects under development with power purchase agreements, all of which are located in British Columbia. Two of these projects, currently under construction, are expected to reach commissioning in 2013, while four are expected to begin construction. All six projects should be in operation by the end of 2016.

On the other side of the country, things have been equally busy for Innergex in the hydroelectric sector. In February 2013, the company announced its intention to acquire Magpie, a 40.6 MW hydroelectric facility in Québec, and signed an exclusive letter of intent with the seller, Hydromega Group of Companies, for the acquisition of another run-of-river hydroelectric facility in Québec and five hydroelectric projects under development with power purchase agreements in Ontario. Innergex management hopes to complete these acquisitions during 2013.

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 Québec, Ontario, British Columbia, and Idaho, USA. In 2012, the company produced 2,148 GWh of electricity, generating revenues of $181 million. As of March 2013, the company had 28 operating facilities with a total net installed capacity of 577 MW, and seven projects under development with a total net installed capacity of 190 MW and 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".

LAMONT CREEK RUN-OF-RIVER HYDROELECTRIC FACILITY IN BRITISH COLUMBIA.

"We have had great success in assuming the operations and maintenance activities at our Baie-des-Sables and L'Anse-à-Valleau wind farms; we have been able to maintain equipment availability in excess of 98%, focus on having equipment available when the wind is blowing, and bring total repair costs down, even as our equipment naturally ages."

– **Peter Grover,** Senior Vice President – Project Management

WIND TURBINE AT THE BAIE-DES-SABLES WIND FARM IN QUÉBEC.

Innergex currently has five wind farms operating in Québec, with a total gross installed capacity of 590 MW. In November 2012, Gros-Morne became the largest wind farm in operation in Canada, with 211.5 MW of installed capacity, when Phase II of the project was commissioned. This achievement also completes the development program of Cartier Wind Energy, Innergex's joint venture with TransCanada Corp. in the wind sector.

Over the years, Innergex has evolved to become both an astute developer and a skilled operator of hydro facilities, an accomplishment it is now reproducing in the wind sector, as Cartier, upon expiry of the five-year maintenance contract with the original equipment manufacturer of the wind turbines, begins to integrate direct operations and maintenance activities at each of its facilities.

In July 2012, Innergex announced a partnership agreement with the Mi'gmaq Nation of Québec for the development, financing, construction, and operation of a large wind farm on the Gaspé Peninsula of Québec.

According to Chief Claude Jeannotte, Chairperson of the Mi'gmawei Mawiomi, *"this project not only aims to produce renewable energy and consolidate the wind industry of Gaspé, it also constitutes a powerful leverage for the emancipation and the long-term socio-economic development of the three Mi'gmaq communities of Gaspé."* Both partners are looking forward to submitting this project under a future call for wind power.

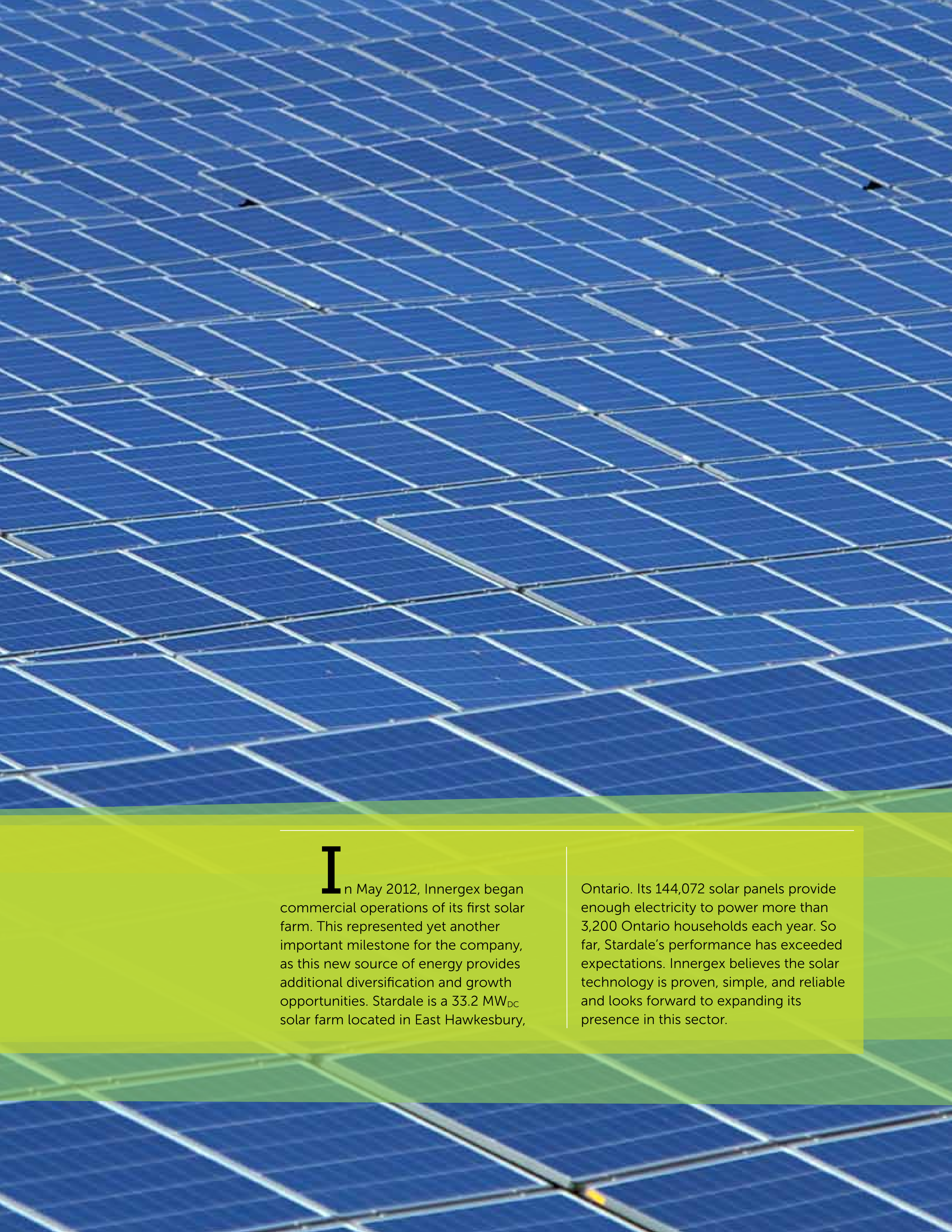
In the spring, Innergex also expects to begin construction of the Viger-Denonville wind project and to commission the facility in the latter part of 2013. Viger-Denonville is the company's first wind project developed in a joint venture with a municipality. It is also the first Québec wind project located in a populated area not to be subject to a public hearing by the BAPE *(Bureau d'audiences publiques sur l'environnement).* This demonstrates the very high social acceptability characterizing this project.

In 2012, Innergex had hoped to expand its wind energy activities into British Columbia with the signing of an agreement to acquire Wildmare, a 77 MW wind energy project; subsequently, several conditions of closing were not met by the prescribed closing date, so the company made the difficult but necessary decision not to proceed with this acquisition. However, Innergex remains committed to working closely with local communities to develop wind operations in British Columbia.

OFFICIAL INAUGURATION CELEBRATIONS

On October 4, 2012, Innergex celebrated the inauguration of its Stardale solar farm during an official ceremony with the Honourable Chris Bentley, Minister of Energy for the Government of Ontario, Grant Crack, MPP for Glengarry-Prescott-Russell, and Robert Kirby, Mayor of East Hawkesbury Township. ***"It is exciting for this area to be recognized for its efforts to improve Ontario's air quality and the reliability of our electricity system. Innergex's solar farm is not only creating clean, renewable electricity for families and businesses, but new local jobs as well."*** **- Grant Crack, MPP, Glengarry-Prescott-Russell**

STARDALE SOLAR FARM IN ONTARIO.



In May 2012, Innergex began commercial operations of its first solar farm. This represented yet another important milestone for the company, as this new source of energy provides additional diversification and growth opportunities. Stardale is a 33.2 MW_{DC} solar farm located in East Hawkesbury, Ontario. Its 144,072 solar panels provide enough electricity to power more than 3,200 Ontario households each year. So far, Stardale's performance has exceeded expectations. Innergex believes the solar technology is proven, simple, and reliable and looks forward to expanding its presence in this sector.

CABLE CRANE AT THE KWOIEK CREEK RUN-OF-RIVER HYDROELECTRIC PROJECT CURRENTLY UNDER CONSTRUCTION IN BRITISH COLUMBIA.

"In 2013, Innergex will undertake an equally ambitious financing program, as we seek to secure more than $700 million in project-level financing. As always, obtaining the best terms at the lowest cost possible in order to maximize returns for our shareholders will be top of mind".

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

Innergex continues to advance its ambitious development program, with seven projects currently under development, including one wind project in Québec and six hydroelectric projects in British Columbia.

Two of these hydroelectric projects, Kwoiek Creek (50 MW) and Northwest Stave (17.5 MW), have been under construction since 2011. Both are progressing on time and on budget, and are expected to reach commissioning in late 2013.

The four remaining hydroelectric projects are at various stages of development. Two important milestones were achieved recently, as the Tretheway Creek and Big Silver Creek projects obtained their Environmental Assessment Certificates in August 2012 and the ULHP cluster of projects (Upper Lillooet and Boulder Creek) received their Environmental Assessment Certificate in January 2013. The company expects to begin construction on these four projects during 2013. All projects are expected to reach commissioning between 2015 and 2016.

On the other side of the country, the Viger-Denonville wind project also reached an important milestone when it received its environmental decree from the Québec government in January 2013, giving it the green light. This project is being developed in a 50-50 joint venture with the Rivière-du-Loup Regional County Municipality. When it reaches commissioning in the latter part of 2013, it is expected to be the first wind farm from the province's 2009 Community Wind Request for Proposals to achieve commercial operations.

Innergex's ambitious development program represents an undertaking of considerable magnitude, with capital expenditures in excess of one billion dollars.

__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

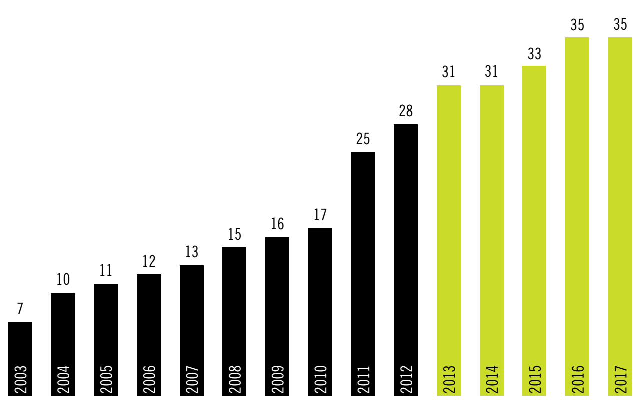
FROM BALANCE COMES SUSTAINABIL

Michel Letellier explains how the balance between social, environmental, and economic considerations forms the basis for a sustainable business model.

Innergex seems to have flourished in recent years; what about in 2012?

In 2012, we brought two new facilities into commercial operation, on time and on budget. One was Stardale, our first solar farm, and the other was Gros-Morne (Phase II), the last of five wind farms developed by our Cartier Wind Energy joint venture. We also acquired two hydroelectric facilities in British Columbia, bringing the total number of sites in operation to 28, in three energy sources and four different jurisdictions. Ten years ago, we had seven hydroelectric facilities, with all but one located in Québec. During 2012, we also entered negotiations to acquire several assets from Hydromega, a private power producer with activities in Québec and Ontario. We hope to conclude these negotiations and further expand our portfolio of assets in 2013.

NUMBER OF SITES IN OPERATION
at December 31
(actual 2003-2012, projected 2013-2017)



ITY

***Chaudière run-of-river** hydroelectric facility in Québec.*

How would you describe Innergex's mission today?

Our mission really hasn't changed since the Company was created in 1990. The course we set then remains absolutely relevant today. We aim to increase our production of renewable energy by developing and operating high-quality facilities while respecting the environment and serving the best interests of the host communities, our partners, and our investors.

What has enabled you to remain successful over the last 22 years?

Innergex's success is founded on developing good projects, which become good operating facilities. For us, a good project is one that is accepted by the local community, respectful of the environment, and economically viable both for us and for the public utilities we service; in other words, a project that balances social, environmental, and economic imperatives – or if you prefer, people, planet, and profits.

Continued on page **14**

Can you explain how these different imperatives influence your activities?

From its beginnings, Innergex has placed social acceptability at the core of its business model. We consult local communities, structuring our projects to include shared ownership or revenues, local job creation, local content requirements, or other special considerations in support of local tourist and recreational activities.

Over the years, we have demonstrated leadership and innovation in sharing the economic benefits of our projects with local communities and First Nations, often creating industry standards for others to follow. We have also proven our capacity to create lasting partnerships with

Baie-des-Sables wind farm
in Québec.

local communities and First Nations across the country – an industry trend we expect will accelerate in the future.

As we all know, any economic activity will have an impact on the environment, but measures can and should be taken to avoid or minimize this impact. Independent power producers must abide by strict federal and provincial regulations designed to protect the environment, from project conception to site operation and restoration. In this area, too, we have demonstrated leadership and innovation in meeting or exceeding the highest environmental standards.

Where do these three imperatives intersect?

There are in fact myriad social and environmental considerations included in crafting a project to be submitted to a public utility under a request for proposals. The proposal must also include a price for the electricity to be produced. Of course, this price must be competitive for the project to be selected. At the same time, this price must take into account the social acceptability of the project, distributions to partners and local community stakeholders, and strict environmental standards in order for the project to be well received. And if there is to be a project at all, this price must also be sufficient for the project to be economically viable.

In other words, the necessary balance between social, environmental, and economic considerations – which together compose the true cost of energy production – must be reflected in the price for the electricity produced.

And why is that important?

When we create this balance, we achieve lasting success. Renewable energy facilities, and hydro in particular, have a very long life span – 25 years in the case of wind and solar, but well over 50 years – even 100 years – in the case of hydro. In keeping with Innergex's vision of providing sustainable energy for a greener future, we want to ensure that we can continue developing and operating high-quality renewable energy facilities, and for a very long time. ■

A camera worth its weight in savings

Cartier Wind Energy has invented a high-precision instrument to inspect wind turbine blades that is safer, faster, and cheaper than anything else on the market.

They say necessity is the mother of invention. For Cartier Wind Energy, the necessity was finding a safer, faster, and less expensive way to inspect turbine blades – all 1,179 of them!

Until now, the only way to inspect turbine blades was by hiring "spidermen" to climb the blades with cameras attached to their helmets. This required stopping the turbine for three to six hours and only allowed for the inspection of one turbine per day, and only one side of each blade.

So Robert Guillemette, General Manager of Cartier Wind Energy and successful inventor in his own right, set out to come up with a better solution. In doing so, he and his team sought the technological expertise of Collineo, a small Montreal-based company specializing in innovative, high-performance, and high-mobility robotics solutions. What they came up with together is a one-of-a-kind instrument: a very high-precision camera mounted on a powerful telescope, which can be quickly guided by remote control to scan the surface of a blade. Lasers on the telescope help to position the instrument and measure distances with great accuracy. Cartier and Collineo share the intellectual property rights to this invention, on which a patent has been filed.

Results so far have been impressive. According to Robert Guillemette, *"the camera has improved health and safety by eliminating the need to climb and rappel the turbines. In addition, it has reduced downtime for each turbine to one hour or less, it scans both sides and the leading edge of each blade, and it allows operators to inspect four to six turbines per day – that's four to six times more than with the old method."* He estimates inspection costs have already been reduced by 70% to 80%.

In addition, the team at Cartier has designed a system to analyze the photos taken with the camera's very powerful zoom lens, detecting cracks as small as a human hair. This allows for the early detection and repair of these cracks, significantly reducing maintenance expenses over time.

The camera will be used at all five of Cartier's wind farms for end-of-warranty and routine inspections (as the operations and maintenance contract with the original equipment manufacturer expires). The company hopes to eventually use it for the preventive maintenance of the blades, which have a life expectancy of 20 years or more. ■

L'Anse-à-Valleau wind farm in Québec.

FOCUS

INNOVATION AT INNERGEX

Innergex is recognized today as a leader in developing, building, operating, maintaining, and financing renewable energy projects. Each new achievement over the years – first in run-of-river hydro, then in wind, and most recently in solar - has served to build its reputation as a Canadian pioneer in the renewable energy industry.

While one operator positions the telescope approximately 30 meters from the turbine, another positions one of the blades perpendicular to the ground and turns it to expose both sides. The camera scans the leading edge and both sides of each blade, taking approximately 25 pictures per side. ■

"We are constantly pushing ourselves and our service providers – with whom we have a very dynamic relationship - to find innovative solutions to the inevitable challenges that arise in the normal course of business. ANDRITZ HYDRO's energy dissipation system offered the best technological solution, from a trusted and reliable supplier."

– **François Hébert,** Senior Vice President – Operations and Maintenance

New challenges call for new solutions

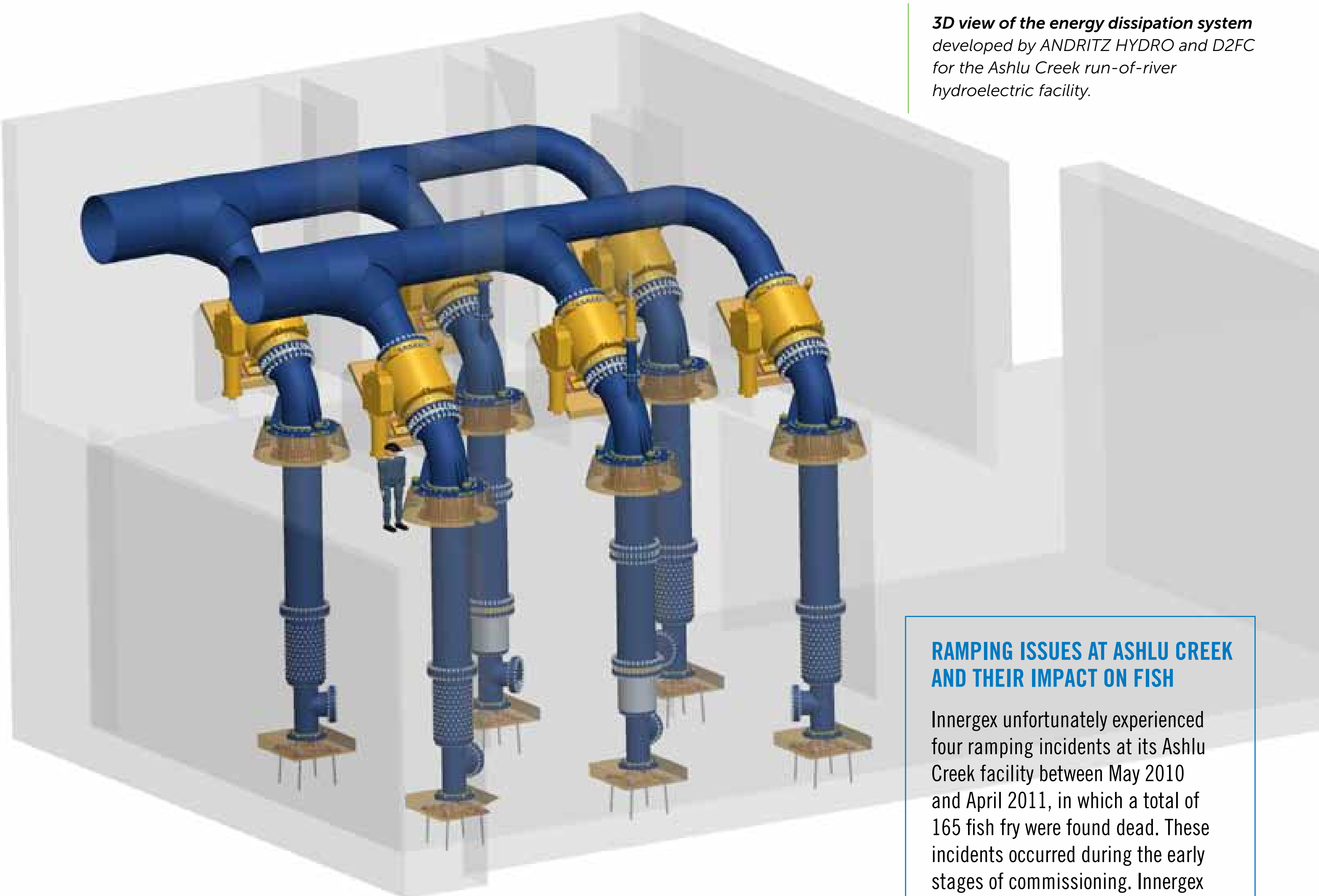
To address stringent ramping regulations and the specific characteristics of its Ashlu Creek run-of-river hydroelectric project, Innergex chose to implement an innovative energy dissipation system, developed for the company by ANDRITZ HYDRO.

The Ashlu Creek run-of-river hydroelectric project's more than 200 meters of head and specific physical characteristics made Francis turbines the most efficient choice. However, unlike Pelton turbines, which are commonly used in British Columbia, Francis turbines make ramping very difficult outside of normal operating conditions.

Ramping is defined as the rate of change in water flows in a stream. It occurs due to changes in the demand for water flow passing through the turbines, as a result of turbine start-up or shut-down. While it is relatively easy to adjust water flows during normal operation of the turbines, the need to suddenly or rapidly change water flows through the turbines (for example, due to equipment failure or loss of connection with the network) creates risks for the river's ecosystem, as well as for the safety of recreational kayakers who may be using the river. Ramping regulations to address these risks have existed in British Columbia since the mid-1990s, and have become increasingly stringent since the mid-2000s.

To address the new and more stringent ecological and environmental requirements associated with ramping, Ashlu's development team needed to find a new technological solution. The request for proposals issued to turbine suppliers specified the ramping criteria, without specifying a particular technology; thus, the door was opened to a new and innovative solution. As it turns out, Innergex found what it deemed to be the most technically appropriate and the most reliable solution in the proposal submitted by ANDRITZ HYDRO, which addressed ramping issues with an inventive energy dissipation system.

The energy dissipation system basically allows water to flow through the hydro plant while bypassing the turbines (when there is a need to shut them down quickly, for example), and therefore allows for a controlled and progressive change of water flows in the stream. To develop this new system, ANDRITZ HYDRO approached and jointly worked with D2FC energy valves SAS, a French valve



***3D view of the energy dissipation system** developed by ANDRITZ HYDRO and D2FC for the Ashlu Creek run-of-river hydroelectric facility.*

manufacturer specializing in hydro-power applications and renowned for its ability to develop reliable, high-performance, and innovative products. D2FC chose to adapt a technology on which the patent had expired that already existed in the United States for hydroelectric facilities with lower head, but that had never been adapted to facilities with higher head.

Innergex found in ANDRITZ HYDRO's proposal a solution to address its ramping requirements at Ashlu Creek and became the first hydro developer to install this new technology in Canada. In turn, its development team successfully completed the critical task of integrating the new technology into the plant's operating system.

For its part, ANDRITZ HYDRO had the opportunity to actually test and implement this new technology at Ashlu Creek. According to Pierre Duflon, Manager Compact Hydro at ANDRITZ HYDRO Canada Inc., *"Innergex is unique in both its in-house concentration of technical expertise in run-of-river hydro that exists nowhere else and its willingness to seek and implement innovative solutions - to 'think outside the box'."* He adds that *"we probably could not have sold this first system to anyone else."* Rising environmental awareness is leading to increasingly stringent ramping regulations in many parts of the world, and ANDRITZ HYDRO has since successfully introduced this system to several small hydro developers in other countries. ■

RAMPING ISSUES AT ASHLU CREEK AND THEIR IMPACT ON FISH

Innergex unfortunately experienced four ramping incidents at its Ashlu Creek facility between May 2010 and April 2011, in which a total of 165 fish fry were found dead. These incidents occurred during the early stages of commissioning. Innergex takes these incidents very seriously, and has made significant improvements at Ashlu Creek to ensure they are not repeated. The company has incurred no fish stranding incidents at Ashlu Creek, or any of its other facilities in British Columbia, since April 2011.

In addition, construction of the Ashlu Creek facility comprised the creation of a fish habitat compensation area spanning almost 53,000 m^2, with many pools and interconnected channels that are equivalent in total area to that of 10 football fields. These compensation areas will be maintained throughout the operating life of the facility. Adult, ocean-going salmon migrate and spawn in this constructed habitat each fall; and tens of thousands of young salmon are produced annually, that return to the ocean to continue their life cycle.

A well-diversified portfolio of assets

Diversification has been proven to reduce risks and improve operating performance stability. Innergex diversifies 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.

Innergex expanded into the British Columbia market in 2002 with the construction of the Rutherford Creek facility. Today, the company operates 11 run-of-river hydroelectric facilities in this province. It also has two hydroelectric projects under construction, four hydroelectric projects under development, and a 1,405 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.

Innergex commissioned its first run-of-river hydroelectric facility, Saint-Paulin, in 1994. In 1999, the company expanded into the Ontario market with the commissioning of its Batawa run-of-river hydroelectric facility. Today, the company operates 11 run-of-river hydroelectric facilities in Eastern Canada. Since 2006, it also diversified its operations, becoming a leading wind energy producer with five wind farms in Québec, including Gros-Morne, the largest wind farm in Canada. In 2012, the company again diversified into a new energy sector with the commissioning of its first 33 MW_{DC} solar farm in Ontario. Innergex currently has one wind farm under development and a 1,495 MW portfolio of prospective hydro, wind, and solar projects in this region.

SITES IN OPERATION

1

ASHLU CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **49.9**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2039**

2

BAIE-DES-SABLES (QC)
DATE OF COMMISSIONING **2006**
INSTALLED CAPACITY (gross MW) **109.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2026**

3

BATAWA (ON)
DATE OF COMMISSIONING **1999**
INSTALLED CAPACITY (gross MW) **50.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2029**

4

BROWN LAKE (BC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **7.2**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2016**

5

CARLETON (QC)
DATE OF COMMISSIONING **2008**
INSTALLED CAPACITY (gross MW) **109.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2028**

6

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

7

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

8

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

9

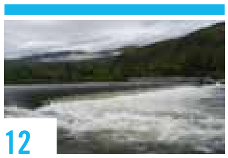
FITZSIMMONS CREEK (BC)
DATE OF COMMISSIONING **2010**
INSTALLED CAPACITY (gross MW) **7.5**
OWNERSHIP (%) **66.67**
PPA EXPIRY **2050**

10

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

11

GROS-MORNE (I & II) (QC)
DATE OF COMMISSIONING **2011**
INSTALLED CAPACITY (gross MW) **211.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2032**



12

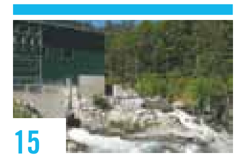
HORSESHOE BEND (USA)
DATE OF COMMISSIONING **1995**
INSTALLED CAPACITY (gross MW) **9.5**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2030**

13

L'ANSE-À-VALLEAU (QC)
DATE OF COMMISSIONING **2007**
INSTALLED CAPACITY (gross MW) **100.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2027**

14

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



15

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

16

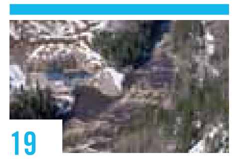
MONTAGNE SÈCHE (QC)
DATE OF COMMISSIONING **2011**
INSTALLED CAPACITY (gross MW) **58.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2031**

17

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

18

PORTNEUF 1 (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **8.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2021**



19

PORTNEUF 2 (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **9.9**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2021**

20

PORTNEUF 3 (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **8.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2021**

21

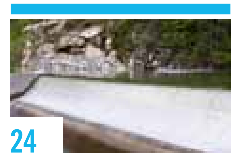
RUTHERFORD CREEK (BC)
DATE OF COMMISSIONING **2004**
INSTALLED CAPACITY (gross MW) **49.9**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2024**

22

SAINT-PAULIN (QC)
DATE OF COMMISSIONING **1994**
INSTALLED CAPACITY (gross MW) **8.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2014**

23

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

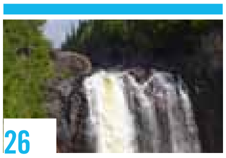


24

STOKKE CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **22.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**

25

TIPELLA CREEK (BC)
DATE OF COMMISSIONING **2006**
INSTALLED CAPACITY (gross MW) **18.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**



26

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

27

UPPER STAVE RIVER (BC)
DATE OF COMMISSIONING **2006**
INSTALLED CAPACITY (gross MW) **109.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2026**

28

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

"We will maintain and even grow spending on prospective projects in the future. These investments, combined with our unique development expertise, will give us the agility and the flexibility to meet the demand for renewable energy capacity, where and when it arises over the long term."

– **Jean Perron,** Chief Financial Officer and Senior Vice President

"All of the projects under development we are currently advancing were originally prospective projects on which we worked, sometimes at length, before having the opportunity to submit them under a request for proposals or a power purchase program. At some point in 2013, we will have six hydroelectric projects under construction simultaneously, a record for the Company. Today, Innergex has more run-of-river hydroelectric sites in British Columbia than any other company."

– **Renaud de Batz,** Senior Vice President – Hydroelectric Development

PROSPECTING 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 advance 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 Ontario Power Authority released revised rules for the province's Feed-In-Tariff Program last August, following a planned review process undertaken in the fall of 2011. While maintaining the province's commitment to clean energy, rule changes have sought to streamline the submission and selection process using a points system, reduce tariffs (22% lower for large solar projects and 15% lower for wind projects) and revise them annually, improve municipal engagement, and encourage Aboriginal and community participation. Domestic content requirements have been maintained. Innergex has a number of wind and solar projects it is preparing to submit under a future Large FIT application window. Other 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, Innergex continues to advance development on a number of projects that would be eligible under the province's Standing Offer Program. In accordance with the terms of this program, all permits and approvals must be obtained prior to submitting a project for a power purchase agreement. Also, the company firmly believes in the potential for wind to become a competitive source of renewable energy for this province. It hopes to capitalize on its strong presence, its positive track record with local communities and First Nations, and its expertise in wind energy as it continues to advance the development of a number of prospective projects.

In Québec, plans have been announced for a new Request for Proposals for the supply of 700 MW of wind energy, including a program for Aboriginal projects. This additional capacity would enable the province to reach its stated objective of developing 4,000 MW of installed wind energy capacity. Innergex remains ready to respond to this new call for wind power, when it comes, and looks forward to submitting a number of projects, including the 150 MW wind project it is developing in partnership with the Mi'gmaq Nation of Québec. ■

It begins with people

Innergex has made social acceptability the cornerstone of its development strategy and in the process has built solid long-term relations with local communities and First Nations across Canada.

In December 2012, Innergex and the Lil'wat Nation signed a Participation Agreement for the Upper Lillooet hydroelectric project under development in British Columbia. This agreement includes a revenue-sharing arrangement, procurement and employment opportunities, and ongoing environmental compliance monitoring. It also includes a provision for the Lil'wat Nation to ensure that the project's design reflects its cultural values. *"It will provide opportunities for employment, contracting and economic development in our Nation for the next generation"* says Chief Lucinda Phillips of the Lil'wat Nation. *"[Innergex has] invested a considerable amount of time in understanding and managing the environmental and archaeological impacts in our traditional territory.*

Continued on page **26**

FOCUS

INNERGEX ENGAGES ITS PARTNERS AND STAKEHOLDERS, GOVERNED BY CORE VALUES OF INTEGRITY, RESPONSIBILITY, TRANSPARENCY, AND COLLABORATION, IN A PERSPECTIVE OF LONGEVITY AND RESOURCE-SHARING.

Inauguration ceremony *at Umbata Falls run-of-river hydroelectric facility in Ontario.*

PARTNERSHIPS BASED ON SOLID LONG-TERM RELATIONS

Harrison facilities

Cloudworks Energy Inc., which Innergex acquired in the spring of 2011, had developed, in its own right, solid relations with several First Nations. Naturally, these First Nations partners chose to take time to understand what this change of ownership would mean for them. They came to recognize in the people of Innergex the same kind of people they had been dealing with previously, who shared the same values of collaboration and First Nations participation in the company's hydroelectric projects. This eventually led to the signing of a new partnership agreement with the Douglas First Nation for the Northwest Stave, Tretheway Creek, and Big Silver Creek projects currently under development.

"A century and a half ago, Port Douglas was the center of commerce in what was to become British Columbia. *Until recently, the people in the Lillooet Valley were a forgotten people. That has changed after the hydro projects came. Many people got jobs. We are now connected to the electricity grid, and have refocused our efforts to important matters like improving our roads, getting phone and Internet services, developing our communities, building a sustainable economy, and bringing our people back home."*

*– **Chief Don Harris** of the Douglas First Nation*

Umbata Falls

The Umbata Falls 23 MW run-of-river hydroelectric facility in Ontario was developed by Innergex in a 49-51 joint venture with the Ojibways of the Pic River First Nation. It began commercial operations in November 2008. For the Pic River First Nation, it was very important that the two operators for the facility be hired from within the community – and that's exactly what happened.

"With Innergex, we have found a partner who respects its commitments; *what it promises, what it says it will do, it does. We look forward to continue working together to develop renewable energy projects for our community."*

*– **Chief Roy Michano** of the Objiways of the Pic River First Nation*

We look forward to working with them on this and other projects into the future." A similar agreement with the Lil'wat Nation is expected to be signed for the company's Boulder Creek hydroelectric project, also under development.

This is the latest of several successful partnerships Innergex has developed over the years, with such partners as the Ojibways of the Pic River First Nation in Ontario, the Kanaka Bar Indian Band and the Douglas First Nation in British Columbia, the Mi'gmaq Nation of Québec, and the Wolf Lake First Nation and the Eagle Village First Nation, also in Québec.

In fact, Innergex has a long history of building solid relations with local communities. By listening to them, by consciously choosing to create projects that reflect their aspirations, and by harmonizing the company's own objectives with those of the communities, it has chosen to begin with people.

Julie Boudreau, Director - Public Affairs, who has first-hand experience in engaging with local communities and First Nations, explains: *"We have always approached development by adapting to the unique circumstances of each community we make contact with. And we have also respected the natural sequence in which social acceptability occurs – first, of the individuals representing the company, then of the company itself, and finally of the company's projects."*

Social acceptability remains the cornerstone of Innergex's development strategy. It has proven an incredible lever of growth over the years, because time and time again

Viger-Denonville

The Viger-Denonville project is a 25 MW wind farm being developed by Innergex in a 50-50 joint venture with the Rivière-du-Loup Regional County Municipality (RCM) – in fact, the company's first joint venture with a municipality. This wind farm is expected to reach commissioning at the end of 2013, but the seeds for it were planted as far back as 2006, when municipal officials visited the company's Baie-des-Sables wind farm, under construction at the time. Contacts were made and, over the years, relationships developed. In 2009, when the provincial government issued a Community Wind Request for Proposals, Innergex and the Rivière-du-Loup RCM formed a partnership and then worked closely together in contacting land owners, structuring a project that was mutually beneficial, and communicating with the local population throughout the process.

"We first chose Innergex because we believed they were a first-rate partner, *one that shared our values. Our experience in working with them on a daily basis confirms it."*

*– **Mr. Michel Lagacé,** Warden of the Rivière-du-Loup RCM*

Kwoiek Creek

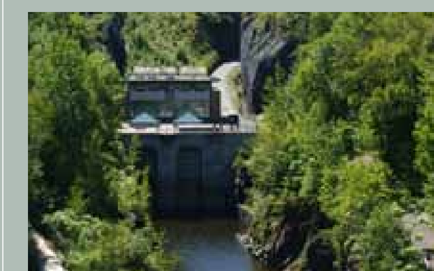
The Kwoiek Creek project is a 50 MW run-of-river hydroelectric facility being developed by Innergex in a 50-50 joint venture with the Kanaka Bar Indian Band. Construction began in 2011 and commercial operations are expected to begin at the end of 2013. For the Kanaka Bar Indian Band, it was very important that this project bring local job creation. Innergex and its suppliers, contractors, and service providers heeded the call; currently, more than 40% of workers at the site are Aboriginal, twice the average for similar construction projects in British Columbia. In fact, in 2012 the Kanaka Bar Indian Band received the Clean Energy Award for Community of the Year from Clean Energy BC, in recognition of the various clean energy initiatives the band has promoted since the 1980s, including the Kwoiek Creek project.

"While many other projects may have First Nations involvement, *I don't think any of them can match us in our one-half Aboriginal ownership and the true partnership we have with Innergex."*

*– **Chief James Frank** of the Kanaka Bar Indian Band*

Chaudière

The idea for the refurbishment of the 24 MW Chaudière run-of-river hydroelectric facility emerged during a period of vocal public opposition to small private hydroelectric facilities. Innergex chose to approach the local communities that would be directly concerned by the project. What they wanted most was to preserve the beautiful falls, so the project was structured around esthetic flow requirements, especially during the summer months when tourism is at its peak. The company also solicited the communities' input in choosing the facility's architectural design, and committed to the revitalization and annual maintenance of the surrounding public nature park, creating a major tourist attraction for the region. In the end, the local communities' firm determination that this project be realized certainly influenced the authorities in giving it a green light.



it has enabled the company to build successful projects. Even more so, it has created projects that are better, because they are in keeping with a sustainable development perspective. Whether in the form of shared economic benefits, employment opportunities, shared ownership, or partnership agreements, Innergex has recognized the growing willingness for communities to become agents of their own socio-economic development. A trend it expects will continue to grow right across Canada. ■

"We believe every community is unique – in its history, its culture, and its aspirations, and we always try to adapt to every community we make contact with. Relations between organizations are based on creating lasting bonds of trust between their people. Building these relationships is very rewarding for everyone involved."

– **Richard Blanchet,** Senior Vice President – Western Region

Develop. Operate. Deliver.

Cartier Wind Energy completes its development program with the commissioning of Phase II of the Gros-Morne wind farm, creating a total of 590 MW of installed wind energy capacity.

When Hydro-Québec announced the first request for proposals for 1,000 MW of wind energy capacity exactly 10 years ago, Innergex made the strategic decision to enter this new renewable energy sector. In early 2004, the company created Cartier Wind Energy with TransCanada Corp., a joint venture in which Innergex owns a 38% interest and a 50% management stake. In September 2004, all the projects Cartier had submitted under the request for proposals were selected, representing three-quarters of the contracts awarded, thus marking the creation of a wind energy industry in Québec.

The commissioning of Phase II of the Gros-Morne wind farm in November 2012 marked the completion of Cartier Wind Energy's development program, successfully delivering five wind projects totalling 590 MW on time and on budget, and providing economic benefits to the Gaspé region in the form of jobs, voluntary contributions to the host municipalities, scholarships, and support for local tourism.

More importantly, Cartier's development program has upheld the highest standards in terms of social acceptability, orderly development, and respect for the environment; it has become a model which other wind industry participants in the province have since adopted.

Cartier's success could not have been achieved without the cooperation and support of the local host communities. *"The people of the Gaspé region have been incredibly supportive of these wind projects"* says Peter Grover, Senior Vice President – Project Management. *"They have played a crucial role in the creation of an industrial and knowledge base in their region for wind energy."*

As the last of its projects under development reaches commercial operation, Cartier has already begun the transition from developer to operator, in much the same way as Innergex has done in the hydro sector. For Robert Guillemette, General Manager of Cartier Wind Energy, *"it's one thing to build wind farms, and quite another to operate them for 20 years. The proper transition to operations is critical. Our personnel are developing a whole new set of technical skills."* Cartier very successfully integrated the operations and maintenance activities of the Baie-des-Sables wind farm in 2011, creating in the process a unit specialized in the preventive maintenance and repair of blades, which resulted in lower operating costs and turbine availability in excess of 98%. Operations and maintenance integration continued in 2012 with the L'Anse-à-Valleau wind farm, and again in 2013 with the Carleton wind farm, as their respective five-year operations and maintenance contracts with the manufacturer expired.

Innergex firmly believes in the long-term prospects for wind energy and remains committed to its development in Québec, as well as other markets across Canada. ■

CARTIER WIND ENERGY HIGHLIGHTS

5 wind farms

393 turbines

590 MW gross installed capacity

Total investments of **$1.1** billion, including $600 million in the Gaspé Peninsula

Produces enough electricity to power more than **100,000** Québec households each year

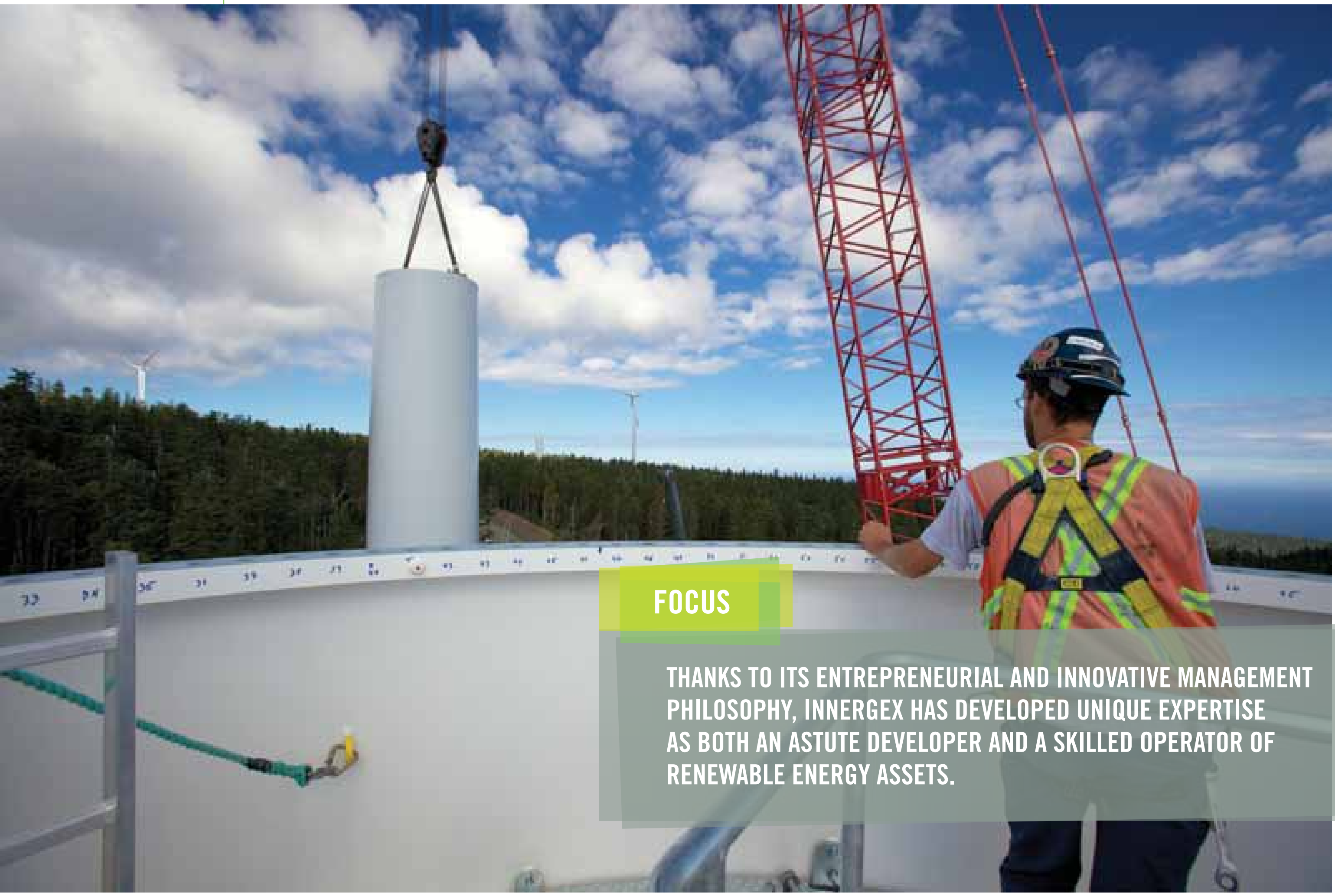
Distributions to the host communities totalling **$15** million over the next 20 years

Six academic grants of **$2,000** each to young people enrolled in the wind turbine industrial maintenance training program at the Cégep de la Gaspésie et des Îles (three open to the general student population, and three specifically for young people from the Gaspé Peninsula's Mi'gmaq communities)

600 persons were involved in the process from design to commissioning of each wind farm, more than 80% of whom were from the region

22 out of Cartier's 27 employees are based in the Gaspé region – this number will probably be closer to 50 by the time all operations and maintenance activities are brought in-house

Installation of a wind turbine *at the Gros-Morne wind farm in Québec.*



FOCUS

THANKS TO ITS ENTREPRENEURIAL AND INNOVATIVE MANAGEMENT PHILOSOPHY, INNERGEX HAS DEVELOPED UNIQUE EXPERTISE AS BOTH AN ASTUTE DEVELOPER AND A SKILLED OPERATOR OF RENEWABLE ENERGY ASSETS.

Acting responsibly through compliance, measurement, and continuous improvement

As a responsible renewable-energy developer and operator, Innergex devotes considerable resources to meeting stringent environmental obligations – Focus on its environmental activities in the British Columbia hydroelectric sector.

British Columbia has been called the greenest province in Canada – a claim that is backed by some of the most comprehensive and stringent environmental regulations in the country. As the largest independent renewable energy developer and operator in the province, with 11 run-of-river hydroelectric facilities in operation and six hydroelectric projects under development, Innergex takes its environmental responsibilities very seriously.

WATER FLOW MONITORING ACTIVITIES

In 2012, the operations team in British Columbia began the implementation of systems to further improve monitoring of the behaviour of the company's hydroelectric facilities in British Columbia. The objectives were clear: to better track the company's license obligations and commitments, better monitor the facilities' effect on the environment, reduce the number of incidents, and perhaps most importantly, proactively respond to incidents as they occur.

While modern hydroelectric stations do monitor plant and river flow in real time, these new systems now allow each facility to monitor water levels in the river in real time, 24/7, and in certain circumstances, to respond in a corrective manner. This helps to ensure that the company's regulatory and contractual commitments are met, particularly those concerning the instream flow, which is the minimum amount of water that must remain in the river at all times. In addition, operators have received additional incident response training, and incident reporting

"The comprehensive, multidisciplinary five-year monitoring programs will enable the Company to better understand and document the real impact of its hydroelectric facilities and better address stakeholder concerns. In turn, knowledge derived from these independent scientific studies will be applied to future project development activities."

– **Matt Kennedy,** Vice President Environment – Western Region

Fish habitat area at the Tipella Creek *run-of-river hydroelectric facility in British Columbia.*

mechanisms have been improved. All incidents, no matter how small, are reported to the federal and provincial government authorities within 24 hours, and followed up with a more detailed report. Most incidents are not material and have no ecological impact. Nevertheless, each incident triggers an internal review to investigate the reasons for the incident and measures are implemented to avoid repetition. *"Respect for the environment is part of our culture; when there is an incident, we investigate immediately and take remedial action when necessary"* states Matt Kennedy, Vice President, Environment – Western Region.

ONGOING MONITORING PROGRAMS

Recent and more stringent environmental regulations in British Columbia require a comprehensive, multidisciplinary five-year monitoring program – of everything from fish, water (chemistry and temperature), insects, and wildlife, to vegetation – to be initiated immediately upon the start of a facility's commercial operation. Such a program serves to confirm the predictions made in the Environmental Impact Assessment for each project as part of the environmental assessment application process.

All of Innergex's British Columbia hydroelectric facilities built within the last five years have this type of comprehensive monitoring program underway, and all facilities (including Brown Lake, which has been in operation for many years and has graduated past the biological monitoring stage) are monitored for their specific compliance requirements. The company has also developed an internal compliance and mitigation policy for all of its facilities in British Columbia, which is now being implemented.

In the process of conducting these comprehensive monitoring programs, Innergex is funding detailed field-based studies and collecting invaluable data. While the company is in the middle stages of monitoring activities for the majority of its British Columbia facilities, results so far are proving encouraging.

Continued on page **32**

Picture of the penstock at the Tipella Creek run-of-river hydroelectric facility, before and after site restoration. ***Bold note:***

SITE RESTORATION MEASURES

Once construction of a project is completed, environmental regulations stipulate that the area around the project must be restored, which means that any impact caused by the project must be rehabilitated or compensated, so that it is in equal or better condition than prior to construction. This entails a variety of measures including land contouring, stabilization, and revegetation. Particular care and consideration are taken to select approved plant species that will provide insects and animals with the same food sources as prior to construction, especially very valuable riparian vegetation[1]. Afterwards, during each year of the initial five-year monitoring program, independent specialists conduct annual surveys to track the results of the rehabilitation and compensation measures.

RESPONSIBLE MANAGEMENT OF RAMPING ISSUES

Ramping[2] issues are relatively rare, and occur mainly during the early phase of commissioning of new hydroelectric facilities. Innergex has learned from experience that fish habitat at some of its sites is more sensitive to changes in water flow, and this informs how quickly the facility can be started up and shut down. In response, the company has developed site-specific procedures for how to manage changes in water levels to protect the ecology of the rivers on which its facilities are located. This has been an area of significant focus over the past few years and is one of continuous improvement.

Despite these efforts, ramping incidents unfortunately do occur from time to time, and in rare instances can cause fish to be stranded. To date, Innergex's hydro facilities in British Columbia[3] have experienced a combined total of four fish-stranding incidents in which a total of 165 fish fry were found dead. These incidents occurred mainly during the early stages of commissioning. Innergex takes these incidents very seriously, responding immediately to isolate the cause and working to ensure it is not repeated. The company has incurred no fish stranding incidents at any of its facilities in British Columbia since April 2011.

1 Plant life and the ecosystem that exist between the land and the water along a waterway.

2 Ramping is defined as the rate of change in water flows in a stream. It occurs due to changes in the demand for water flow passing through the turbines, as a result of turbine start-up or shut-down.

3 Facilities that were acquired are taken into account as of the date of their acquisition.

FOCUS

INNERGEX'S VISION IS TO PROVIDE SUSTAINABLE ENERGY FOR A GREENER FUTURE.

FISH HABITAT COMPENSATION

Fish habitat protection and compensation measures are prescribed under the federal *Fisheries Act*. Concurrent with the construction of several of its hydroelectric projects, Innergex has built a number of fish habitat areas in British Columbia, ranging in size from nearly 4,000 m^2 to over 50,000 m^2. Adult, ocean-going salmon migrate and spawn in several of these constructed freshwater habitats each fall; and many thousands of young salmon are produced annually, that return to the ocean to continue their life cycle. What's more, these compensation areas will be maintained throughout the operating life of the hydroelectric facilities. ■

Innergex has built a number of fish habitat areas at its facilities in British Columbia. *The Ashlu Creek compensation area is by far the largest, spanning almost 53,000 m^2, with many pools and interconnected channels that are equivalent in total area to that of 10 football fields. Both the Kwoiek Creek and Northwest Stave River hydroelectric facilities, currently under construction, will also include construction of fish habitat compensation areas.*

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

INTERVIEW

STABILITY AND SECURE GROWTH

Mr. Jean La Couture, Chairman of the Board, summarizes the role and priorities of the Board of Directors of Innergex.

Mr. La Couture, what is the priority for the Board of Directors of Innergex?

As always, the stability and the secure growth of Innergex remain our absolute priorities.

What does this mean concretely?

The Board of Directors fully supports management's decision to favour internal growth through the development of renewable energy projects, in order to create added value for its shareholders.

While not excluding the possibility of external growth, the management team intends to remain opportunistic in the study of potential acquisitions.

What role do you believe the board of directors must play in a public company?

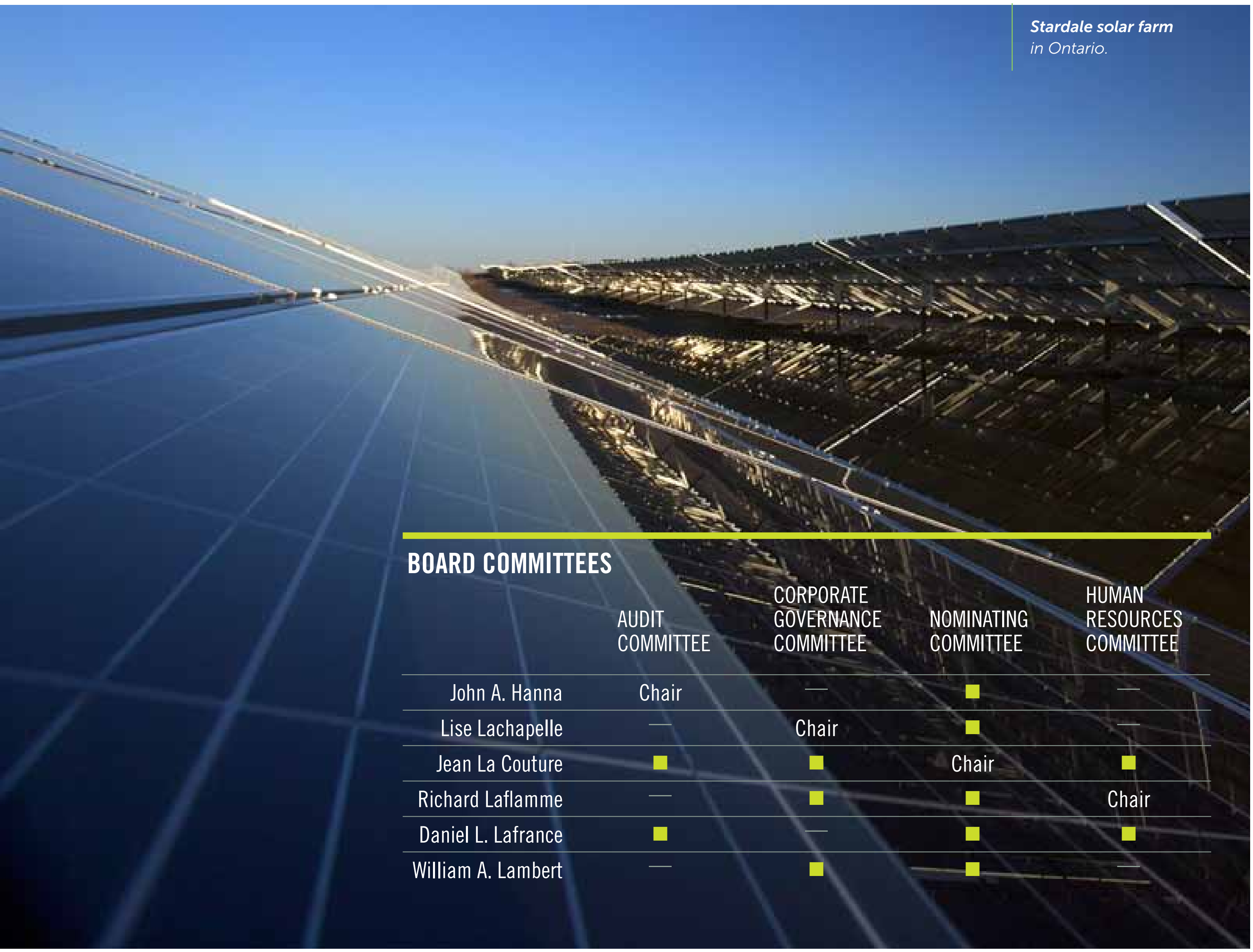
The primary function of a board of directors is to protect the best interests of the company's shareholders and, by extension, of all its stakeholders.

For the Board of Directors of Innergex, the best way to exercise this responsibility is to adhere to best practices in corporate governance. This is also consistent with a sustainable development approach, as a complement to the integration of social, environmental, and economic considerations in the conduct of the Company's activities.

This is something you've been doing for a number of years. Are there other changes in sight?

Indeed, we have worked to improve our practices in the last few years, namely with respect to risk management – involving a thorough review of processes for the management and disclosure of risks, succession planning, and executive compensation.

In the spirit of the small-steps theory, we continue to improve our way of working, while remaining attentive to the opportunities and challenges presented by the renewable energy industry for the Company. ■



Stardale solar farm in Ontario.

BOARD COMMITTEES

	AUDIT COMMITTEE	CORPORATE GOVERNANCE COMMITTEE	NOMINATING COMMITTEE	HUMAN RESOURCES COMMITTEE
John A. Hanna	Chair	—	■	—
Lise Lachapelle	—	Chair	■	—
Jean La Couture	■	■	Chair	■
Richard Laflamme	—	■	■	Chair
Daniel L. Lafrance	■	—	■	■
William A. Lambert	—	■	■	—

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: Senior Vice President Finance and Procurement, CFO and Secretary, Lantic Inc., wholly owned by Rogers Sugar Inc.
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

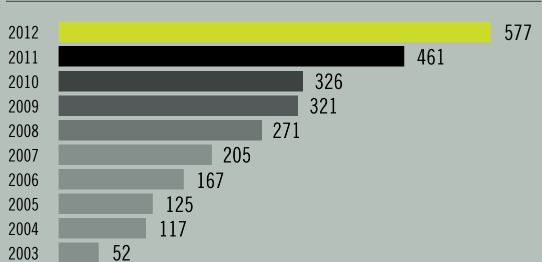
*John A. Hanna, Lise Lachapelle, Jean La Couture, Richard Laflamme and Daniel L. Lafrance were appointed directors of the Corporation on March 29, 2010 upon completion of the strategic combination of Innergex Power Income Fund and Innergex Renewable Energy Inc. Prior to the strategic combination, they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

Financial and operational highlights

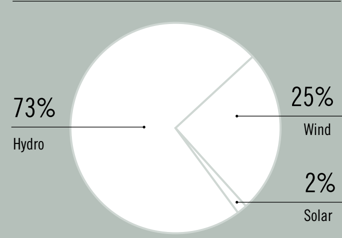
FINANCIAL OVERVIEW For the years ended December 31 (in thousands of Canadian dollars, except as noted)	2012[1]	2011[1]	2010[1b]	2009[2]	2008[2]
Power generated (MWh)	**2,148,450**	1,905,426	1,227,435	823,989	862,394
Gross operating revenues	**180,860**	148,260	91,385	58,625	59,430
Adjusted EBITDA[3]	**137,583**	111,196	68,111	46,778	47,097
Dividend declared - $ per Series A preferred share	**1.25**	1.25	0.42	-	-
Dividend declared - $ per Series C preferred share[4]	**n/a**	-	-	-	-
Dividend declared - $ per common share	**0.58**	0.58	0.61	0.68	0.68

1 Prepared in accordance with IFRS.
1b Converted in accordance with IFRS.
2 Prepared in accordance with Canadian GAAP.
3 Defined as operating revenues less operating expenses, general and administrative expenses, and prospective project expenses.
4 Series C preferred shares were issued on December 11, 2012.

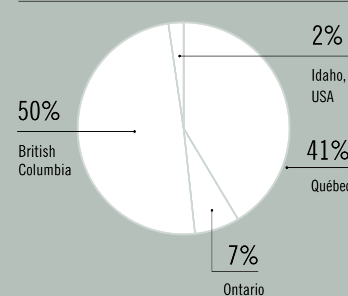
NET INSTALLED CAPACITY
At December 31
(GWh)



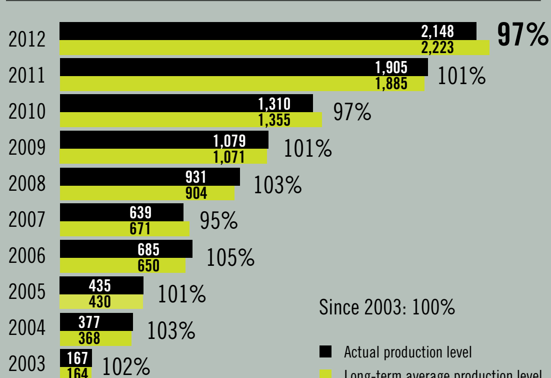
ENERGY SOURCE DIVERSIFICATION
Based on actual consolidated production
(GWh)



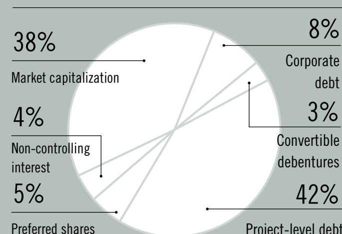
GEOGRAPHIC DIVERSIFICATION
Based on actual consolidated production
(GWh)



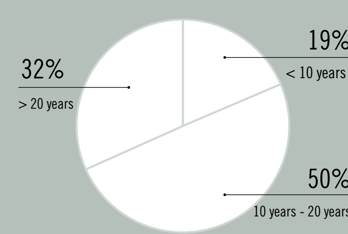
PRODUCTION PREDICTABILITY
(GWh)



CAPITAL STRUCTURE
At December 31
($M)



PPA REMAINING TERMS
Based on net long-term average production of operating facilities (GWh)



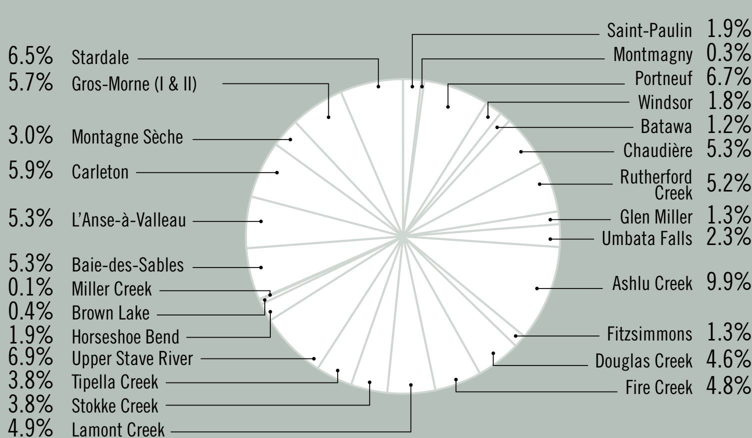
PROJECTS UNDER DEVELOPMENT

	PROJECT	LOCATION	GROSS CAPACITY (MW)	INE'S OWNERSHIP	ESTIMATED CONSTRUCTION COSTS ($M)	COSTS AS AT DEC. 31, 2012 ($M)	EXPECTED IN-SERVICE DATE
WIND	Viger-Denonville[1]	QC	24.6	50.0 %	36.6	3.4	Q4 2013
HYDRO	Kwoiek Creek	BC	49.9	50.0%	153.2	96.8	Q4 2013
	Northwest Stave River	BC	17.5	100%	91.4	51.3	Q4 2013
	Tretheway Creek	BC	23.2	100%	108.5	14.8	2015
	Boulder Creek	BC	25.3	66.7%	116.9	2.5	2015
	Upper Lillooet	BC	81.4	66.7%	317.6	7.5	2016
	Big Silver Creek	BC	40.6	100%	191.8	28.0	2016

1. Costs correspond to the Corporation's 50% interest in this project.

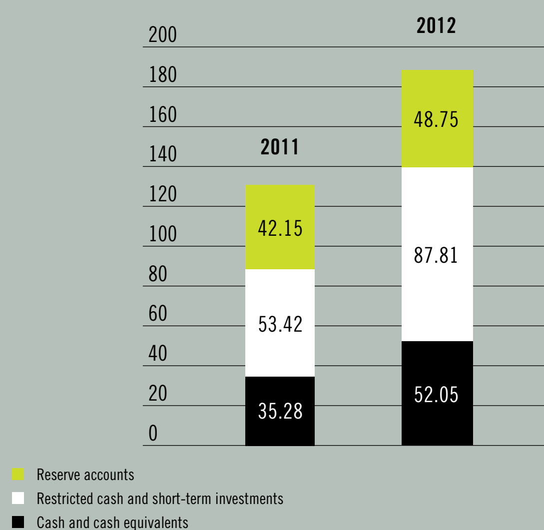
REVENUE BREAKDOWN BY SITE

Based on 2012 operating revenues
($M)



CASH AND RESERVE ACCOUNTS

At December 31, 2012
($M)



2012 HIGHLIGHTS

Electricity production increased by year-over-year **13%**

Operating revenues rose 22% to **$181M**

Total net installed capacity increased 25% to **577 MW**

28 the number of operating facilities at year-end

73% the proportion of energy produced from hydro

The electricity we produce was enough to power **180,000** Canadian households

Over **$400M** of debt and equity raised in the capital markets

First solar farm of **33 MW$_{DC}$** reaches commercial operation

Implementation of a **DRIP** (Dividend Reinvestment Plan)

Report card

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

PERFORMANCE	2012		2013	
Power generated	2,148 GWh	+13%		+10% [1]
Operating revenues	$180.9M	+22%		+10% [1]
Adjusted EBITDA	$137.6M	+24%		+10% [1]
Number of facilities in operation at year-end[2]	28		31	
Net installed capacity at year-end	577 MW	+25%	631 MW	+9%
Consolidated average production, annualized	2,460 GWh	+15%	2,684 GWh [1]	+9%

WE SAID WE WOULD	WE DID	WE EXPECT TO
FINANCING		
Finance Kwoiek Creek	Achieved ✓ $168.5M, 5.08% 40-year term	—
Finance Northwest Stave	90% complete	Finalize - approx. $75M
Maintain a balanced capital structure in financing growth so as to preserve the Company's low risk profile	Achieved ✓ Increase in credit facility of $75M Common share issue of $124M Series C preferred share issue of $50M Implementation of a DRIP	Refinance Carleton - approx. $42M Finance the ULHP[3] - approx. $370M Finance Tretheway and Big Silver Creek - approx. $220M Finance Viger-Denonville - approx. $55M
PROJECT DEVELOPMENT		
Commission Stardale solar farm	Achieved ✓ May 16, 2012	—
Commission Phase II of Gros-Morne wind farm	Achieved ✓ November 6, 2012	—
Advance construction of Kwoiek Creek hydro facility	Achieved ✓ Project remains on schedule and on budget	Commission in Q4
Advance construction of Northwest Stave hydro facility	Achieved ✓ Project remains on schedule and on budget	Commission in Q4
Advance permitting of Tretheway Creek and Big Silver Creek hydro projects	Achieved ✓ Environmental Assessment Certificates received on August 20, 2012	Begin construction of Tretheway Creek and Big Silver Creek
Advance permitting of the ULHP[3]	Achieved ✓ Environmental Assessment Certificate received on January 10, 2013	Begin construction of Boulder Creek and Upper Lillooet
Advance permitting of Viger-Denonville wind farm	Achieved ✓ Environmental Decree received on January 23, 2013 Project remains on schedule and on budget	Begin construction in the spring Commission in Q4
—	—	Complete capex program at Miller Creek in the fall
EXTERNAL GROWTH OPPORTUNITIES		
Continue to study M&A opportunities while remaining selective and disciplined in our approach	Acquired Brown Lake and Miller Creek hydro facilities in BC	—
	Announced acquisition of Magpie hydro facility in Québec	Complete the acquisition
	Signed a letter of intent to acquire other Hydromega assets	Complete the acquisition
	—	Pursue M&A opportunities that contribute immediately to cash flow generation

1 As of January 1, 2013, the Umbata Falls and Viger-Denonville joint ventures will have to be accounted for using the equity method, rather than the proportionate accounting method used previously, pursuant to IFRS changes taking effect (IAS 28(2011)). These sites will be excluded starting in 2013.

2 Phases I and II of the Gros-Morne wind farm are counted as one site.

3 ULHP comprises the Upper Lillooet and Boulder Creek hydroelectric projects.

Information for investors

COMMON SHARES (TSX: INE)

Innergex Renewable Energy Inc. had 93,659,866 common shares outstanding at December 31, 2012, with a closing price of $10.35 per share. The company's shares are listed on the Toronto Stock Exchange, and are part of the S&P/TSX SmallCap Index and the S&P/TSX Clean Technology Index.

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. They are rated P-3 by Standard & Poor's and Pfd-3 (low) by DBRS.

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. They are rated P-3 by Standard & Poor's and Pfd-3 (low) by DBRS.

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 and the redemption date specified by the Company (no earlier than April 30, 2013, except in certain limited circumstances). 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, Québec, 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. implemented a Dividend Reinvestment Plan ("DRIP") for its common shareholders, which came into effect on August 31, 2012 and which 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.

FOCUS

INNERGEX'S STRATEGY FOR BUILDING SHAREHOLDER VALUE IS TO DEVELOP OR ACQUIRE HIGH-QUALITY FACILITIES GENERATING SUSTAINABLE CASH FLOWS AND PROVIDING 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.

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Longueuil, Québec, Canada J4K 5G4

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INNERGEX

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Sustainable Development.

INNOVATION

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Renewable Energy.
Sustainable Development.

FINANCIAL REVIEW
AT DECEMBER 31, 2012

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INNERGEX

MANAGEMENT’S DISCUSSION AND ANALYSIS
(in thousands of Canadian dollars, except as noted, and amounts per share)

The following is a discussion of the financial position, operating results and cash flows of Innergex Renewable Energy Inc. (“Innergex” or the “Corporation”) for the year ended December 31, 2012. This Management's Discussion and Analysis (“MD&A”) reflects all material events up to March 14, 2013, the date on which this MD&A was approved by the Corporation's Board of Directors. This MD&A should be read in conjunction with the audited consolidated financial statements and the accompanying notes for the year ended December 31, 2012. Additional information relating to Innergex, including its Annual Information Form, can be found on the Canadian Securities Administrator's 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 annual financial statements attached to this MD&A and the accompanying notes for the year ended December 31, 2012, along with the 2011 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, 2012, 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, 2012. There was no change to the ICFR during the year ended December 31, 2012, that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR other than the following. During the year, the Corporation has automated processes in order to reduce the likelihood of human errors.

FORWARD-LOOKING INFORMATION

In order to inform shareholders of the Corporation as well as potential investors in the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws ("Forward-Looking Information"). All information and statements other than statements of historical facts contained in this MD&A are forward-looking information. Forward-Looking Information can generally be identified by the use of words such as "about", "approximately", "may", "will", "could", "believes", "expects", "intends", "should", "plans", "predict", "potential", "project", "anticipates", "estimates", "budget", "scheduled", or "forecasts", or similar words or the negative thereof or other comparable terminology that state that certain events will or will not occur.

The Forward-Looking Information includes forward-looking financial information or financial outlook, within the meaning of securities laws, such as expected production, projected revenues, project costs, adjusted EBITDA or results to inform investors and shareholders of the potential financial impact of development projects if and when they will reach commercial operation, recently announced acquisitions or expected results. Such information may not be appropriate for other purposes.

Forward-Looking Information represent, as of the date of this MD&A, the estimates, forecasts, projections, expectations or opinions of the Corporation relating to future events or results. Forward-Looking Information involve known and unknown risks, uncertainties and other important factors which may cause the actual results or performance to be materially different from those expressed, implied or presented by the Forward-Looking Information. The material risks and uncertainties that may cause the actual results and developments to be materially different from the current expressed expectations are referred to in this MD&A under the “Risks and Uncertainties” heading and include the ability of the Corporation to execute its strategy; the ability to access sufficient capital resources; liquidity risks related to derivative financial instruments; changes in hydrology, wind regime and solar irradiation; delays and cost over-runs in the construction and design of projects; health, safety and environmental risks; uncertainty relating to development of new facilities; obtainment of permits; variability of project performance and related penalties; equipment failure; interest rate fluctuation and refinancing risk; financial leverage and restrictive covenants governing current and future indebtedness; declaration of dividends at the discretion of the board; securing new power purchase agreements; the ability to retain senior management and key employees; litigation; performance of major counterparties; relationship with stakeholders; equipment supply; changes to regulatory and political factors; the ability to secure appropriate land; reliance on power purchase agreements; reliance upon transmission systems; water and land rental expense; assessment of water, wind and sun resources and associated energy production; dam safety; natural disasters and force majeure; foreign exchange fluctuations; sufficiency of insurance coverage; credit rating may not reflect actual performance of the Corporation; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired and to be acquired; failure to realize the anticipated benefits of acquisitions; fluctuation of the revenues from the Miller Creek facility based on the electricity spot price; the inability to execute a definitive agreement and close the acquisition of the Hydromega hydroelectric facilities and development projects; failure of the shared transmission and interconnection infrastructure and the introduction of solar photovoltaic power facility operation.The forward-looking information is based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions concerning availability of capital resources, absence of exercise of any termination right, economic and financial conditions, the success obtained in developing new facilities and the performance of operating facilities. Although the Corporation believes that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information since no assurance can be given that they will prove to be correct. The reader of this MD&A is cautioned not to rely unduly on this Forward-Looking Information. Forward-Looking Information, expressed verbally or in writing by the Corporation or by a person acting on its behalf, is expressly qualified by this cautionary statement. The 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.

OVERVIEW

General

The Corporation is a developer, owner and operator of renewable power-generating facilities. The Corporation's shares are listed on the Toronto Stock Exchange (“TSX”) under the symbols INE, INE.PR.A and INE.PR.C. The Corporation has been active in the Canadian renewable power industry since 1990, with a focus on hydroelectric, wind power and solar photovoltaic (“PV”) projects that benefit from low operating and management costs and simple proven technologies. The Corporation is rated BBB- by Standard and Poor's Rating Services (“S&P”) and BBB (low) by DBRS Limited (“DBRS”).

Portfolio of Assets

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

- 28 facilities that are in commercial operation (the “Operating Facilities”). Commissioned between November 1994 and November 2012, the facilities have a weighted average age of approximately 6.9 years. They sell the generated power under long-term Power Purchase Agreements (“PPA”) that have a weighted average remaining life of 18.2 years;

- seven projects scheduled to begin commercial operation on planned dates (the “Development Projects”). Construction is ongoing at three of the projects and is expected to begin on the remaining four projects between 2013 and 2014. The projects are expected to reach the commercial operation stage between 2013 and 2016; 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 submitted under a Request for Proposal (“RFP”) or could be submitted under a Standing Offer Program (“SOP”) or Feed-In Tariff Program (“FIT Program”) (collectively the “Prospective Projects”). These projects are at various stages of development.

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

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

INNERGEX

Renewable Energy.
Sustainable Development.

	Operating Facilities	Development Projects	Prospective Projects
Hydro			
Gross capacity:	408.5 MW	237.9 MW	1,000.0 MW
Net capacity[1]:	319.3 MW	177.4 MW	950.0 MW
Wind			
Gross capacity:	589.5 MW	24.6 MW	2,085.0 MW
Net capacity[1]:	224.0 MW	12.3 MW	1,910.0 MW
Solar			
Gross capacity:	33.2 MW	-	40.0 MW
Net capacity[1]:	33.2 MW	-	40.0 MW
Total			
Gross capacity:	1,031.2 MW	262.5 MW	3,125.0 MW
Net capacity[1]:	576.5 MW	189.7 MW	2,900.0 MW

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

Annual Dividend Policy

The Corporation intends to distribute an annual dividend of $0.58 per common share payable quarterly. Its dividend policy is based on the long-term cash flow generating capacities of its Operating Facilities. Innergex's investments in the Development Projects and Prospective Projects are financed through cash flows and a combination of additional indebtedness and equity.

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"); and operating revenues less operating expenses, general and administrative expenses and prospective project expenses ("Adjusted EBITDA"). These indicators are not recognized measures under IFRS and therefore may not be comparable with those presented by other issuers. The Corporation believes that these indicators are important since they provide management and the reader with additional information about its production and cash generation capabilities and facilitate the comparison of results over different periods.

Seasonality

The amount of energy generated by the Operating Facilities is generally dependent on the availability of water flows, wind regime and solar irradiation. Lower than expected water flows, wind regime 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 22 hydroelectric facilities, which draw on 19 watersheds, five 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:

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

	LTA[1] (GWh and %) - Net Interest[2]								
Energy	Q1		Q2		Q3		Q4		Total
HYDRO	248.8	14%	630.0	36%	506.7	29%	359.7	21%	1,745.2
WIND	213.6	32%	142.8	21%	112.8	17%	207.3	31%	676.5
SOLAR[3]	7.4	19%	12.6	33%	12.8	33%	5.9	15%	38.7
Total	469.8	19%	785.4	32%	632.3	26%	572.9	23%	2,460.4

1. Long-term average for 2013 for the facilities in operation at December 31, 2012.
2. Net interest adjusted in accordance with revenue recognition accounting rules under IFRS.
3. Solar farm LTA diminishes over time due to expected solar panel degradation.

BUSINESS STRATEGY

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

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. 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 Development Project), the Rivière-du-Loup Regional County Municipality ("RCM") (owner of 50% of the Viger-Denonville community wind project) and Ledcor Power Group Ltd. (owner of $33^1/_3$% of the Fitzsimmons Creek facility, the Boulder Creek, North Creek and Upper Lillooet Development Projects and other Creek Power Inc. Prospective Projects). Current financial partners include CC&L Infrastructure LP and LPF Infrastructure Fund (owners of 34.99% and 15.00% of Harrison Hydro LP respectively).

Areas of 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 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 set ambitious targets for 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, the provincial government has indicated its intention to increase its supply of renewable energy from wind sources through an upcoming RFP, the details of which have yet to be announced. The Corporation has a number of prospective projects that it could submit under a future call for power in this province, including a 150 MW wind project developed in partnership with the Mi'gmaq Nation of Quebec.

In Ontario, the Ontario Power Authority ("OPA") revised the rules of its Feed-in Tariff Program ("FIT Program") in August 2012. While maintaining the province's commitment to clean energy, rule changes have aimed to streamline the submission and selection process using a points system, reduce tariffs (22% lower for larger solar projects and 15% lower for wind projects) with annual revision, improve municipal engagement and encourage Aboriginal and community participation. Domestic content requirements have been maintained, although these are currently being challenged at the World Trade Organization. A Small FIT application window was opened from December 14, 2012, to January 18, 2013 (for projects up to 500 kW). A Large FIT application window is expected in 2013. The Corporation has a number of projects that it could submit under Ontario's FIT Program (see the "Prospective Projects" section of this MD&A).

In British Columbia, BC Hydro revised the terms of its SOP in January 2011. Among other things, it increased the upper limit on project size (from 9.9 MW to 15.0 MW) and the electricity rates applicable to each region. The Corporation has several Prospective Projects that could be eligible under this program, which it continues to investigate for submission.

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 renewed focus on increasing renewable energy production. The White House's Blueprint for a Secure Energy Future calls for 80% of electricity generated in the U.S. to come from a diverse set of low carbon energy sources by 2035, "including renewable energy sources like wind, solar, biomass and hydropower". Renewable energy generation from wind and solar sources has more than doubled in the United States in the last four years, accounting for 2.7% of net electricity generation in the first nine months of 2012.

Diversification
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 its efforts on developing 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 growth opportunities to come from Canada and the United States.

Key Growth Factors
The Corporation's future growth will be affected by six key factors:

i) the public's and governments' demand for renewable energy;
ii) its capacity to evaluate and secure the best prospective sites for the development of new projects in cooperation with local communities;
iii) its ability to enter into attractive PPAs and obtain the required environmental and other permits;
iv) its ability to adequately forecast total construction costs, expected revenues and expected expenses for each project;
v) its ability to make accretive acquisitions; and
vi) the availability of financing.

Capacity for Delivering Results
As the Corporation evolves in a competitive sector, the experience and dedication of its management team are its strongest asset. Due to its careful management of the process, the team has a proven track record of completing projects by the commercial operation start date specified in its PPAs without incurring any significant cost overruns. 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 a proven ability to complement its internal capabilities with an efficient use of external consultants when required. In addition, the Corporation uses the services of several independent engineering firms to assist with the feasibility analysis of its projects. At as December 31, 2012, the Corporation employed a total of 146 persons (including Cartier Wind Energy employees).

MARKET TRENDS
Renewable power producers are involved in the generation of electricity from renewable energy sources including:

i) hydro;
ii) wind;
iii) solar;
iv) biomass (e.g. waste wood from forest products operations) and landfill gas; and
v) geothermal sources, such as heat or steam.

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 a number of reasons to explain the growing role played by independent power producers in supplying renewable power in North America, including:

i) the growing demand for energy;
ii) the availability of long-term renewable energy purchase contracts with high 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;
iii) the implementation of non-discriminatory access to transmission systems, providing independent power producers with access to regional electricity markets;

iv) the efficiency of independent power producers; and
v) the increase in government-sponsored incentives.

However, natural gas prices have been declining over the last few years. This price variation could impact demand for renewable energy over the short-term as well as renewable power selling prices included in future PPAs.

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. Several provinces are also expecting to make significant transmission grid investments in order to bring this power to market.

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 structure 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. 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;
- New Brunswick – To generate 10% of total electricity from renewable resources by 2016 and to have 40% of in-province electricity sales provided from renewable energy by 2020;
- Newfoundland and Labrador – To develop 80 MW of wind energy on the island of Newfoundland;
- Nova Scotia – To generate 25% of total electricity from renewable resources by 2015 and 40% by 2020;
- Ontario – To increase hydro energy capacity to 9,000 MW (+10.7%) and to develop 10,700 MW of installed wind, solar and bioenergy capacity by 2018;
- 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.

As a result, several provinces have released, revised, or are currently preparing significant new RFPs, SOPs and FIT Programs, with the objective of procuring additional electricity generation capacity from renewable sources. 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.

Canada enjoys a unique abundance of hydrological resources. With an estimated installed hydroelectric capacity of more than 70,000 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 6,201 MW at the end of 2012, an 18% increase from the preceding year. In addition, more than 6,000 MW of wind energy projects are contracted to be built over the next four 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 customary 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, especially in Ontario. At March 31, 2012, the Ontario Power Authority reported 482 MW of solar PV installed capacity in commercial operation, with an additional 1,536 MW of capacity under development. While Ontario is expected to remain the dominant market for solar photovoltaic manufacturing and deployment in Canada, governments at all levels across the country are considering incentives to encourage the development of the Canadian solar industry, which should continue to post substantial growth rates over the next decade.

2012 DEVELOPMENTS

Closing of the Kwoiek Creek Project Financing

On July 17, 2012, the Corporation announced that the Kwoiek Creek Resources Limited Partnership closed a $168.5 million non-recourse construction and term project financing for the Kwoiek Creek project. The construction loan carries a fixed interest rate of 5.075%; it will convert into a 39-year term loan following the start of the project's commercial operation and will amortize over a 36-year period starting three years later. The financing has been arranged with a group of life insurance companies comprised of The Manufacturers Life Insurance Company as agent and lead lender and of The Canada Life Assurance Company and The Great-West Life Assurance Company as lenders.

Increase of the Revolving Term Credit Facility to $425.0 million

On July 17, 2012, Innergex announced that it had exercised a portion of the accordion feature on its revolving term credit facility, increasing its borrowing capacity from $350.0 million to $425.0 million. All terms and conditions remain unchanged, including an August 2016 maturity.

Partnership Agreement with the Mi'gmawei Mawiomi

On July 20, 2012, the Corporation and the Mi'gmawei Mawiomi (the Mi'gmaq of Quebec) announced that they had concluded a partnership agreement for the development, financing, construction and operation of a 150 MW wind farm on the Gaspé Peninsula in Quebec. The two partners intend to submit the project under a future RFP for the commissioning of wind energy.

Announcement of a Potential Acquisition of an Operating Hydroelectric Facility in Quebec

On July 26, 2012, the Corporation announced that it had signed a purchase and sale agreement to acquire from the Hydromega Group of Companies ("Hydromega") its 70% interest in the Magpie facility located in the Minganie Regional County Municipality (RCM), in northeastern Quebec. The Corporation also signed a letter of intent with Hydromega regarding the acquisition of its equity interest in six other sites, including one 30.5 MW hydroelectric facility in Quebec, four hydroelectric projects under construction totaling 22.0 MW in Ontario, and one 10.0 MW hydroelectric project under development also in Ontario, all of them with PPAs. Concurrently, Innergex entered into a $25 million deposit agreement, which bears an interest rate of 7% annually and which is to be applied against the purchase price of any Hydromega asset, upon closing of the acquisition.

Magpie is a 40.6 MW run-of-river hydroelectric facility with an estimated yearly energy output of 185,000 MWh. All the power produced is sold to Hydro-Québec under a power purchase agreement maturing in 2032. In January 2013, Hydromega completed renegotiations with the Minganie RCM, giving Hydromega essentially all the equity interest in Magpie, in exchange for which the Minganie RCM i) owns a convertible debenture which entitles it to a 30% equity interest in the facility upon conversion of the debenture on January 1, 2025, and ii) receives additional annual royalties until the debenture is converted.

The final purchase price of Magpie will be $28.4 million plus a working capital adjustment and the assumption of approximately $51.0 million in fixed-rate project-level debt. In addition, from August 31, 2012 to the closing date of the acquisition, most of the net cash flows generated by Magpie will have accrued to the Corporation.

The acquisitions of Magpie and the other Hydromega assets have not yet closed due to a number of reasons, which include the renegotiations between Hydromega and the Minganie RCM, the obtainment of the required consent from Hydromega's senior lenders, and the partial reorganization of Hydromega's corporate structure. It is now expected that the acquisition of Magpie will close concurrently with the acquisition of the other Hydromega assets, over the coming months.

The Corporation perceives the delays in closing these transactions as merely short-term setbacks, as it believes that Hydromega's operating facilities and projects under development are very high quality, long-term hydroelectric assets and that their acquisition will contribute positively to its operating performance and cash flow generation in the years to come.

Furthermore, upon closing of the anticipated acquisition of the Hydromega assets, the Corporation expects to issue approximately $125 million of common equity, including $75 million in payment to Hydromega shareholders, rather than make additional drawdowns on the revolving term credit facility.

Private Placement of Common Shares Totaling $123.7 million

On July 26, 2012, the Corporation announced the closing of a private placement with the Caisse de dépôt et placement du Québec and one other institutional investor to issue a total of 12,040,499 common shares at a price of $10.27 per share for gross proceeds of $123.7 million. A portion of these proceeds has been used to finance the Brown Lake and Miller Creek hydroelectric facilities' acquisition closed on October 12, 2012, and for the $25.0 million deposit for the potential acquisition of any Hydromega assets.

Implementation of a Dividend Reinvestment Plan

On August 31, 2012, the Corporation implemented a dividend reinvestment plan ("DRIP") for its shareholders. The plan allows eligible common shareholders the opportunity to reinvest a portion or all of the dividends they receive to purchase additional common shares of the Corporation in an efficient and cost effective manner. Shares can either be purchased on the open market or issued from treasury. Since the implementation, plan shares purchased under the DRIP were issued from treasury on October 15, 2012, and January 15, 2013, and their purchase price was $10.52 and $9.93 respectively. The prices were based on the weighted-average trading price of the common shares on the Toronto Stock Exchange during the five business days immediately preceding the dividend payment date less a discount of 2.5%. Any decision made by the Corporation's board of directors (the “Board of Directors”) 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.

For more information about Innergex's DRIP, please contact Computershare or visit the Investors/Dividend Reinvestment Plan section of www.innergex.com.

Termination of the Wildmare Wind Project Acquisition in British Columbia

On October 1, 2012, the Corporation announced that it had terminated its agreement with Finavera Wind Energy to acquire its 77 MW Wildmare wind energy project located in British Columbia. Despite the efforts of both parties, several conditions of closing were not met by the prescribed closing date of September 30, 2012. The Corporation considered each of these conditions to be essential to the successful completion of the project. After careful consideration, the Corporation decided not to extend the closing date.

Completion of the Acquisition of Two Operating Hydro Facilities in British Columbia

On October 12, 2012, the Corporation announced that it had completed the acquisition of the Brown Lake and Miller Creek run-of-river hydroelectric facilities located in British Columbia from Capital Power Corporation. The purchase price of $68.6 million and associated transaction costs of this acquisition were financed by a combination of drawdowns on the Corporation's revolving term credit facility and a portion of the proceeds from a private placement of common shares completed in July 2012.

Brown Lake is a 7.2 MW facility with an average annual production of 51,800 MWh. The electricity it produces is sold to BC Hydro under a power purchase agreement which expires in 2016. The Corporation expects to double the plant's installed capacity to 14.4 MW and increase its expected average annual production by 27,000 MWh for an additional investment of approximately $20.0 million. Miller Creek is a 33 MW facility with an average annual production of 97,900 MWh. The electricity it produces is sold to BC Hydro under a power purchase agreement which expires in 2023. The Corporation expects to upgrade the penstock and water intake which should increase the plant's expected average annual production by 4,895 MWh, for an additional investment of approximately $8.5 million.

Issuance of Preferred Shares Totaling $50.0 million

On December 11, 2012, the Corporation announced that it had completed a bought deal offering of Cumulative Redeemable Fixed-Rate Preferred Shares Series C ("Series C Preferred Shares"). The Corporation issued a total of 2,000,000 Series C Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $50.0 million. The offering was made on a bought deal basis through a syndicate of underwriters co-led by TD Securities Inc., National Bank Financial Inc. and BMO Capital Markets. The Corporation used the proceeds to repay a portion of its revolving term credit facility and for general purposes. The holders of the Series C Preferred Shares are entitled to receive fixed cumulative preferential cash dividend as and when declared by the Board of Directors at an annual amount equal to $1.4375.

The Series C Preferred Shares are rated P-3 by S&P and Pfd-3 (low) by DBRS.

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

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.

SELECTED ANNUAL INFORMATION

For the years ended December 31	2012	2011	2010
Power generated (MWh)	2,148,450	1,905,426	1,227,435
Revenues	180,860	148,260	91,385
Operating and general and administrative expenses	38,865	34,591	20,903
Net loss	(5,383)	(43,704)	(68,703)
Net earnings (loss) attributable to			
owners of the parent	1,405	(40,547)	(68,635)
($ per common share - basic)	(0.03)	(0.59)	(1.13)
($ per common share - diluted)	(0.03)	(0.59)	(1.13)
Weighted average number of common shares (in 000)	86,557	75,681	55,530
Total assets	2,323,953	2,033,409	947,140
Long-term financial liabilities:			
Debt related to operating facilities	1,013,031	892,873	349,127
Debt related to projects under construction	223,143	148,511	7,086
Debt related to projects under development	17,927	8,129	2,476
Derivative financial instruments	64,023	71,158	22,597
Accrual for acquisition of long-term assets	13,063	41,267	—
Liability portion of convertible debentures	79,655	79,490	79,334
Dividends declared on Series A Preferred Shares	4,250	4,250	1,431
Dividends declared on common shares	50,693	43,990	26,086
Equity attributable to owners	580,321	464,717	358,900

Comparison between 2012, 2011 and 2010
For the year ended December 31, 2012, the increases in the power generated, the revenues and the operating and general and administrative expenses are attributable mainly to the addition of the Montagne Sèche and Gros-Morne wind farms, the Stardale solar farm and the Brown Lake and Miller Creek hydroelectric facilities. The addition of six hydroelectric facilities ("Harrison Operating Facilities") as part of the acquisition of Cloudworks Energy Inc. ("Cloudworks Acquisition"), realized in April 2011, also explains the increases. The increases in long-term debts are attributable mainly to the Montagne Sèche, Stardale and Kwoiek Creek loans and to drawings on the revolving term credit facility for Gros-Morne and Northwest Stave River. The increase in shareholders' equity is due mainly to issuance of common and preferred shares.

The main differences between 2011 and 2010 are attributable to the Cloudworks Acquisition.

The decrease in net loss between 2012 and 2011 is attributable mainly to an unrealized net gain on derivative financial instruments of $8.3 million in 2012 compared with an unrealized net loss on derivative financial instruments of $61.5 million in 2011 and a $26.4 million increase in Adjusted EBITDA, which is detailed in the Financial Results table, partly offset by a $10.2 million increase in finance costs and a $14.8 million increase in depreciation and amortization. The decrease in net loss in 2011 from 2010 is due mainly to an increase in revenues, partly offset by increases in operating and general and administrative expenses (net variation of $43.2 million). It can also be explained by a $51.8 million unrealized loss on unitholders' capital registered in 2010, partly offset by a $61.5 million unrealized net loss on derivative financial instruments (net loss of $20.8 million in 2010).

The following table outlines the impact of the unrealized and realized net gain (loss) on derivative financial instruments, the unrealized loss on unitholders' capital and the distributions declared to unitholders prior to the combination of Innergex Power Income Fund and Innergex on March 29, 2010, on the net loss:

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

For the years ended December 31	2012	2011	2010
Net loss	(5,383)	(43,704)	(68,703)
Add (deduct): Unrealized net (gain) loss on derivative financial instruments	(8,342)	61,479	20,761
Add: Realized loss on derivative financial instruments	14,127	—	—
Add: Unrealized loss on unitholders' capital	—	—	51,761
Add: Distributions declared to unitholders	—	—	7,238
Less: Deferred income tax recoveries related to the above elements	1,504	16,599	5,605
Total	(1,102)	1,176	5,452

The increases in dividends declared on common shares from 2010 to 2011 and from 2011 to 2012 are due mainly to the increase in the weighted average number of common shares outstanding.

COMMISSIONING ACTIVITIES

The following table presents the Operating Facilities that have been commissioned during the last 12 months:

Project name and location	Net installed capacity (MW)	Net estimated LTA (GWh)	Total project costs			Original estimate & actual COD[2]	Expected year-one	
			Estimated[1] ($M)	Revised[1] ($M)	As at Dec 31, 2012 ($M)		Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
SOLAR (Ontario)								
Stardale	33.2	39.0	141.7	141.7	138.9	Q2 2012	16.4	15.0
WIND (Québec)								
Gros-Morne II[3]	42.2	129.6	68.0 [4]	65.1 [4]	64.4	Q4 2012	9.0 [4]	7.8 [4]

1. This information is intended to inform the reader of the projects' potential impact on the Corporation's results. The actual results may vary. Please refer to the "Forward-Looking Information" section for details.
2. Commercial operation date.
3. All data correspond to the Corporation's 38% interest in this project.
4. See the "Gros-Morne II" paragraph below for more details.

Stardale

On May 16, 2012, Innergex announced that the Stardale solar farm ("Stardale") had begun commercial operation. This solar farm is located in East Hawkesbury, Ontario.

Stardale comprises approximately 144,000 SolarWorld polycrystalline photovoltaic modules for a total installed capacity of 33.2 MW_{DC} (27 MW_{AC}) and an estimated initial annual energy output of 39,000 MWh. All of the energy delivered by Stardale is covered by three fixed-price, 20-year term Renewable Energy Standard Offer Program contracts ("RESOP contracts") with the Ontario Power Authority. During its first eight months of operation, Stardale produced 33,374 MWh.

Gros-Morne II

On November 6, 2012, Innergex announced that the Gros-Morne wind farm Phase II (Gros-Morne II) had begun commercial operation. This wind farm is located in the municipalities of Saint-Maxime-du-Mont-Louis and Sainte-Madeleine-de-la-Rivière-Madeleine, in the Gaspé Peninsula of Quebec.

The commissioning of Gros-Morne II completes Cartier Wind Energy's development program, which encompasses 589.5 MW of gross installed wind energy capacity in Quebec. Innergex owns a 38% interest and a 50% management stake in Cartier Wind Energy.

Gros-Morne II comprises 74 wind turbines with a total installed capacity of 111.0 MW and an estimated yearly energy output of 341,135 MWh. Following the commissioning of Gros-Morne II, Gros-Morne Phase I and II will hereafter be referred to as one wind farm with a total gross installed capacity of 211.5 MW and an expected average annual production of 650,000 MWh. All of the electricity produced is sold to Hydro-Québec under a 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 November 2032.

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

Project cost and revenue adjustments of Gros-Morne

The estimated total project costs were revised to be adjusted for the indices included in the turbine supply agreement. As the PPA provides for a corresponding adjustment to the selling price received from Hydro-Québec based on similar indices, the expected year-one revenues and Adjusted EBITDA were also revised and adjusted accordingly.

DEVELOPMENT PROJECTS

The Corporation currently has seven projects that are expected to reach the commercial operation stage between 2013 and 2016.

PROJECTS UNDER CONSTRUCTION

Project name and location	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[1] ($M)	As at Dec 31, 2012 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
HYDRO (British Columbia)									
Kwoiek Creek	50.0	49.9	Q4 2013	215.0	40	153.2	96.8	18.2	14.8
Northwest Stave River	100.0	17.5	Q4 2013	61.9	40	91.4	51.3	7.4	5.9
WIND (Québec)									
Viger-Denonville	50.0	24.6	Q4 2013	67.6	20	36.6 [2]	3.4 [2]	5.2 [2]	4.2 [2]

1. This information is intended to inform the reader of the projects' potential impact on the Corporation's results. The actual results may vary. Please refer to the "Forward-Looking Information" section for details.
2. Corresponding to the Corporation's 50% interest in this project.

Hydro

Kwoiek Creek

The construction of this hydroelectric facility began in the last quarter of 2011. By the end of 2012, the powerhouse steel superstructure was completed; the intake construction was still under way; and the transmission line construction and penstock installation were ongoing. At the date of this MD&A, the construction was progressing as scheduled and budgeted. Current activities also include assembly and installation of the turbines and generators. The fish habitat compensation channel construction has been halted for the winter period and will resume in the spring of 2013.

Northwest Stave River

The construction of this hydroelectric facility began in the last quarter of 2011. By the end of 2012, all civil works at the powerhouse was nearly completed and the river diversion was completed. At the date of this MD&A, the construction was progressing as scheduled and budgeted. As planned, construction activities have been halted for the winter period; they will resume in the spring of 2013.

Wind

Viger-Denonville

The government decree and the Certificate of Authorization for wood clearing were received in January 2013. At the date of this MD&A, the engineering, procurement and construction contract had been executed and the relevant permits and Certificate of Authorization for the construction received. Current activities include wood clearing, road construction and site mobilization.

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

PROJECTS UNDER PERMIT PHASE

Project name and location	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA (GWh)	PPA term (years)	Total project costs Estimated[1] ($M)	Revised ($M)	As at Dec 31, 2012 ($M)
HYDRO (British Columbia)								
Boulder Creek	66.7	25.3	2015	92.5	40	84.2	116.9	2.5
Tretheway Creek	100.0	23.2	2015	81.9	40	91.5	108.5	14.8
North Creek	66.7	16.0	2016	59.7	40	72.0	72.0	0.1
Upper Lillooet	66.7	81.4	2016	334.0	40	264.2	317.6	7.5
Big Silver Creek	100.0	40.6	2016	139.8	40	165.4	191.8	28.0

1. This information is intended to inform the reader of the projects' potential impact on the Corporation's results. The actual results may vary. Please refer to the "Forward-Looking Information" section for details.

Hydro

Boulder Creek, North Creek, and Upper Lillooet

In January 2013, an important milestone was reached when these projects received their Environmental Assessment Certificate from the province of British Columbia. Current activities include ongoing consultation with stakeholders and applications for obtaining the relevant permits. Proposals from civil works contractors, turbine and generator suppliers and transmission line contractors were received at the beginning of 2013. In light of these proposals, the Corporation has elected, as allowed pursuant to the projects' power purchase agreement and permits, to increase the installed capacity of the Upper Lillooet project from 74.0 MW to 81.4 MW and of the Boulder Creek project from 23.0 MW to 25.3 MW. Annual electricity generation for the two projects has also increased, from 355.9 GWh to 426.5 GWh. However, subject to B.C. Hydro's consent, the North Creek project will be cancelled.

As a result, total installed capacity for this cluster of projects decreases 5.6% to 106.7 MW, but annual electricity generation increases 2.6% from 415.6 GWh to 426.5 GWh. In aggregate, total project costs are expected to increase by $14.1 million, or 3.3%, and will be shared between two larger projects instead of three. The increase in costs is due mainly to higher than expected civil engineering and logistics costs, as well as the return to a provincial sales tax system. The Corporation believes this new configuration is economically more attractive and entails lesser environmental, construction and financing risks, making the projects easier and less expensive to operate.

The Corporation still expects to start construction on the Boulder Creek and Upper Lillooet projects in 2013 and meet their original expected commercial operation dates. Furthermore, the Corporation intends to continue advancing a revised version of the North Creek project in view of a future request for proposals.

Tretheway Creek

As of early March 2013, the turbine supplier had been selected and preliminary engineering was ongoing. Current activities also include hydrometric monitoring, environmental studies, consultation with the various stakeholders and applications for obtaining the relevant permits. More detailed analysis of the hydrology has demonstrated lower water flows than initially expected in the river. In view of these findings, the Corporation anticipates that the installed capacity will be increased by 9.4% to 23.2 MW, as allowed pursuant to the project's power purchase agreement, in order for the expected annual electricity generation to remain constant at 81.9 GWh.

Proposals from civil works contractors, turbine and generator suppliers, and transmission line contractors were received at the beginning of 2013. Total project costs are expected to increase by approximately $17.0 million, or 18.6%, as a result of greater installed capacity, higher than expected civil costs, and the return to a provincial sales tax system. The Corporation is actively pursuing different alternatives with the bidders to bridge the gap between the proposals and the original estimated project costs. The Corporation still expects to start construction on this project in 2013 and meet the original expected commercial operation date.

Big Silver-Shovel Creek
Current activities include hydrometric monitoring, consultation with the various stakeholders, applications for obtaining the relevant permits and preliminary engineering. As the Corporation indicated when the projects were acquired, it requested and received authorization to amend the PPA to exclude the Shovel Creek project and increase the installed capacity of the Big Silver Creek project by 10% to 40.6 MW. Despite the increased installed capacity, more detailed analysis of the hydrology has demonstrated lower water flows than initially expected, resulting in a 5% reduction in the expected annual electricity generation to 139.8 GWh. Total project costs are expected to increase by approximately $26.4 million, or 16%, as a result of greater installed capacity, more expensive civil works regarding the transmission line (and especially the submarine cable), higher than expected tunnel and penstock costs, and the return to a provincial sales tax system. The Corporation is actively pursuing different alternatives to bridge the gap between the new and the original estimated project costs. Furthermore, the Corporation believes this new configuration is economically more attractive and entails fewer construction and financing risks, making the project easier and less expensive to operate.

The Corporation expects to start construction on this project in 2013 and meet the original expected commercial operation date. Furthermore, it intends to continue advancing a revised version of the Shovel Creek project in view of a future request for proposals.

The Corporation expects to finance the anticipated cost increase of $57.5 million for the projects under permit phase partly with approximately $40.0 million of additional project-level financings and partly with the additional equity contributions from its dividend reinvestment plan.

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, SOPs or FIT Programs 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 for the year ended December 31, 2012, which is filed at www.sedar.com.

OPERATING RESULTS
The Corporation's operating results for the year ended December 31, 2012, are compared with the operating results for the same periods in 2011.

Electricity Production
When evaluating its operating results, the Corporation compares actual electricity generation with a long-term average for each hydroelectric facility, wind farm and solar farm. These long-term averages are determined carefully and prudently to allow long-term forecasting of the expected generation for each of the Corporation's facilities.

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

For the years ended December 31	2012				2011			
	Production (MWh)	LTA (MWh)	Production as a % of LTA	Average[1] price ($/MWh)	Production (MWh)	LTA (MWh)	Production as a % of LTA	Average[1] price ($/MWh)
HYDRO								
Quebec	350,148	348,430	100%	82.72	390,504	348,430	112%	77.24
Ontario	114,634	128,005	90%	75.57	122,056	128,005	95%	73.44
British Columbia	1,064,888	1,095,126	97%	77.60	998,303	982,021	102%	75.61
United States	49,552	46,800	106%	67.91	41,983	46,800	90%	65.09
Subtotal	1,579,222	1,618,361	98%	78.28	1,552,846	1,505,256	103%	75.57
WIND								
Quebec	535,854	572,734	94%	84.01	352,580	379,275	93%	86.26
SOLAR								
Ontario[2]	33,374	31,548	106%	349.90	—	—	—	—
Total	2,148,450	2,222,643	97%	83.93	1,905,426	1,884,531	101%	77.57

1. Including all payment adjustments linked to month, day and hour of delivery; environmental attributes and the ecoENERGY Initiative as applicable.
2. Average price includes energy delivered before COD which was priced at market rates. All energy delivered post-COD is priced at $420/MWh.

During the year ended December 31, 2012, the Corporation's facilities produced 2,148 GWh, 3% less than the LTA of 2,223 GWh. This production level is due mainly to low water flows in British Columbia in the first and fourth quarters and in Quebec and Ontario in the third quarter. The United States facility performed above its LTA. Wind conditions were slightly lower than anticipated at all the wind farms except the Montagne Sèche wind farm. Also, converters damaged in December 2011 after a load rejection event required that repairs be carried out at the Gros-Morne Phase I wind farm during the first half of the first quarter of 2012. Production resumed on February 12, 2012, allowing the facility to reach 49% of its first quarter LTA. The Stardale solar farm performed above its LTA.

The overall performance of the Corporation's facilities for the year ended December 31, 2012, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind and solar power generation.

Additional Information
Power Purchase Agreements
The 28 Operating Facilities sell the generated power under long-term PPAs to rated public utilities. 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, which receives a price based on a formula using the Dow Jones Mid-C pricing indices. For the Horseshoe Bend hydroelectric facility, 85% of the price is fixed and 15% is annually adjusted and 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 mitigates the inflation fluctuation effects on revenues:

- all PPAs for Quebec hydroelectric facilities provide for a CPI-based power rate increase of minimum 3% and maximum 6% per year;
- PPAs for the Glen Miller and Umbata Falls hydroelectric facilities provide for an annual power rate adjustment based on 15% of the CPI;
- PPA for the Brown Lake hydroelectric facility in British Columbia provides for a power rate increase of 3% per year;

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

- all PPAs for British Columbia hydroelectric facilities except the Brown Lake and the Miller Creek facilities provide for an annual power rate adjustment based on 50% of the CPI; and
- all PPAs for Quebec wind farms provide for an annual power rate adjustment based on approximately 20% of the CPI.

Financial results

For the years ended December 31	2012	2011
Operating revenues	180,860	148,260
Operating expenses	29,133	24,226
General and administrative expenses	9,732	10,365
Prospective project expenses	4,412	2,473
Adjusted EBITDA	137,583	111,196
Finance costs	63,281	53,122
Other net expenses	15,527	2,693
Depreciation and amortization	65,737	50,970
Unrealized net (gain) loss on derivative financial instruments	(8,342)	61,479
Provision (recovery) for income taxes	6,763	(13,364)
Net loss	(5,383)	(43,704)
Net earnings (loss) attributable to:		
Owners of the parent	1,405	(40,547)
Non-controlling interests	(6,788)	(3,157)
	(5,383)	(43,704)

Revenues
For the year ended December 31, 2012, the Corporation recorded operating revenues of $180.9 million ($148.3 million in 2011). This increase is due mainly to the additional revenues from the Stardale solar farm ($11.7 million) and the Montagne Sèche and Gros-Morne wind farms ($14.6 million). Additional revenues from the Harrison Operating Facilities, acquired on April 4, 2011, ($5.2 million) and the Brown Lake and Miller Creek hydroelectric facilities, acquired on October 12, 2012 ($1.0 million), also contributed to this increase. These elements were partly offset by lower production levels at the Quebec hydroelectric facilities (lower revenues of $1.2 million).

Expenses
Operating expenses consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance and property taxes and royalties.

For the year ended December 31, 2012, the Corporation recorded $29.1 million in operating expenses ($24.2 million in 2011). This increase is due mainly to the Corporation's operating a greater number of facilities in 2012 than in 2011 following the Cloudworks Acquisition ($1.5 million) and the addition of the Stardale solar farm and the Montagne Sèche and Gros-Morne wind farms ($1.8 million).

General and administrative expenses totalled $9.7 million for the year ended December 31, 2012 ($10.4 million in 2011).

Prospective project expenses include the costs incurred for the development of Prospective Projects. Prospective project expenses totalled $4.4 million for the year ended December 31, 2012 ($2.5 million in 2011). The difference reflects the Corporation's increased project development efforts.

Finance Costs
Finance costs include interest on long-term debt and convertible debentures, inflation compensation interest, amortization of financing fees, amortization of the revaluation of long-term debt and convertible debentures, accretion expense on asset retirement obligations and accretion expense on contingent considerations.

For the year ended December 31, 2012, finance costs totalled $63.3 million ($53.1 million in 2011). This difference is due mainly to the increase in the interest on long-term debt resulting from the Cloudworks Acquisition, the Stardale and Montagne Sèche term loans and the drawings under the revolving credit term facility for Gros-Morne. These items were partially offset by lower inflation compensation interest.

As at December 31, 2012, 95% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (88% as at December 31, 2011). The difference is due to the Fitzsimmons Creek and Stardale interest rate swaps, which became effective during the first and third quarter of 2012 respectively.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 5.70% as at December 31, 2012 (5.99% as at December 31, 2011). The decrease stems mainly from lower inflation compensation interest rates related to the real return bonds due to a lower inflation rate, partly offset by higher interest rates on Stardale, which is now hedged by an interest rate swap contract, higher interest rates on the revolving credit term facility and additional long-term interest rate swap contracts. Please see the "Derivative Financial Instruments and Risk Management" section for more information.

Other Net Expenses
Other net expenses include the transaction costs, realized loss on derivative financial instruments, realized gain on foreign exchange, (gain) loss on contingent considerations, loan impairment, compensation from contractor and other net revenues.

For the year ended December 31, 2012, other net expenses totalled $15.5 million ($2.7 million in 2011). This increase is due mainly to a realized loss on derivative financial instruments related to the settlement of the Kwoiek Creek bond forwards. This loss results from the decrease in benchmark interest rates between the date the bond forwards were entered into (between September and November 2011) and the settlement date (July 2012) and is compensated by the Kwoiek Creek low fixed interest rate of 5.075% for its 39-year term loan. The loss was partly offset by interest revenues on reserve accounts and on the deposit for the potential acquisition of any Hydromega assets and by compensation from a contractor received in 2012 and related to Stardale.

Depreciation and Amortization
For the year ended December 31, 2012, depreciation and amortization expenses totalled $65.7 million ($51.0 million in 2011). This increase is attributable mainly to the larger asset base resulting from the Cloudworks Acquisition, the Stardale solar farm and the Montagne Sèche and Gros-Morne wind farms.

Derivative Financial Instruments
The Corporation uses derivative financial instruments to manage its exposure to the risk of rising interest rates on its debt financing and to the risk of rising foreign currencies on its equipment purchases ("Derivatives"), thereby protecting the economic value of its projects. Innergex also has derivative financial instruments embedded in some of its PPAs. 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 year-to-year variations in long-term interest rates.

For the year ended December 31, 2012, the Corporation recorded an $8.3 million unrealized net gain on derivative financial instruments (loss of $61.5 million in 2011) due mainly to the settlement of the Kwoiek Creek bond forwards and the increase in benchmark interest rates since the end of 2011. By realizing the loss related to the Kwoiek Creek bond forwards, the negative value of the unrealized derivative financial instruments decreased compared with last year. In 2013, the Corporation expects to settle the Northwest Stave River and Viger-Denonville bond forwards, which will result in a realized gain or loss on derivative financial instruments.

For the year ended December 31, 2012, the Corporation recorded a $0.4 million unrealized net gain on foreign exchange contracts. The forward exchange contracts secure the exchange rate on planned equipment purchases for the Viger-Denonville project. The foreign exchange contracts will expire during 2013, which will result in a realized gain or loss on foreign exchange.

Provision for Income Taxes
For the year ended December 31, 2012, the Corporation recorded a current provision for income taxes of $2.0 million (provision for income taxes of $0.5 million in 2011) and a deferred provision for income taxes of $4.8 million (deferred recoveries of income taxes of $13.8 million in 2011). The difference is due primarily to the unrealized net gain on derivative financial instruments recognized in 2012 compared with the unrealized net loss on derivative financial instruments recognized in 2011.

Net Earnings (Loss)
For the year ended December 31, 2012, the Corporation recorded a net loss of $5.4 million (basic and diluted net loss of $0.03 per share). For the corresponding period of 2011, Innergex recorded a net loss of $43.7 million (basic and diluted net loss of $0.59 per share). The following two tables outline the main items that contributed to this favourable variation in net loss:

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

Main items - Positive impact	Variation	Explanation
Adjusted EBITDA	26,387	Due mainly to the additional revenues from the commissioning of Stardale, Montagne Sèche and Gros-Morne and to additional revenues from the Brown Lake and Miller Creek facilities and the Harrison Operating Facilities for the first quarter of 2012.
Unrealized net gain on derivative financial instruments	69,821	Due mainly to a decrease in benchmark interest rates from the end of 2010 to the end of 2011, compared with the settlement of the Kwoiek Creek bond forwards in 2012.

Main items - Negative impact	Variation	Explanation
Finance costs	10,159	Primarily due to the Cloudworks Acquisition, to greater usage under the revolving credit term facility and to the Stardale and Montagne Sèche loans.
Other net expenses	12,834	Due mainly to the realized loss related to the Kwoiek Creek bond forwards settled in 2012.
Depreciation and amortization	14,767	Primarily due to the Cloudworks Acquisition, Stardale, Montagne Sèche and Gros-Morne.
Provision for income taxes	20,127	Due mainly to earnings before income taxes in 2012 compared with a loss before income taxes in 2011.

The basic and diluted per-share figures for the year ended December 31, 2012, are based on a weighted average number of 86,557,479 and 86,707,993 common shares outstanding respectively. 1,263,000 stock options were non-dilutive during this period, as the average market price of the Corporation's common share was below the strike price. The other 1,473,684 stock options were anti-dilutive in the per-share figure calculation, despite the average market price of the Corporation's common share being above the strike price, as the Corporation recognized a net loss for the period. Convertible Debentures were non-dilutive, as the average market price was below the conversion price. A total of 7,558,684 common shares could potentially have been issued on conversion of the convertible debentures.

The basic and diluted per-share figures for the year ended December 31, 2011, were based on a weighted average number of 75,681,128 and 75,754,667 common shares outstanding respectively. 1,869,420 stock options were non-dilutive during this period, as the average market price of the Corporation's common share was below the strike price. The other 808,024 stock options were anti-dilutive in the per-share figure calculation, despite the average market price of the Corporation's common share being above the strike price, as the Corporation recognized a net loss for the year ended December 31, 2011. Convertible Debentures were non-dilutive for the year ended December 31, 2011, as the average market price was below the conversion price. A total of 7,558,684 common shares could potentially have been issued on conversion of the convertible debentures.

As at December 31, 2012, the Corporation had a total of 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 December 31, 2011, it had 81,282,460 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares and 2,677,444 stock options outstanding. As at the date of this MD&A, the Corporation had a total of 93,964,093 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 2,736,684 stock options outstanding. The increase in the number of common shares since December 31, 2012, is attributable to the DRIP.

Non-controlling Interests

For the year ended December 31, 2012, the Corporation allocated losses of $6.8 million to non-controlling interests (losses of $3.2 million in 2011). These non-controlling interests are related mostly to the Harrison Operating Facilities, the Fitzsimmons Creek Operating Facility and the Kwoiek Creek Development Project.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows from Operating Activities

For the year ended December 31, 2012, cash flows generated by operating activities totalled $62.2 million ($43.4 million in 2011). This difference is due primarily to a $26.4 million increase in Adjusted EBITDA and a positive variation of $24.0 million in changes in non-cash operating working capital items, partly offset by a $15.3 million increase in interest paid and a $14.1 million realized loss on derivative financial instruments. The variation in non-cash working capital items stems mainly from a decrease in accounts receivable compared with an increase in 2011, an increase in prepaid and others compared with a decrease in 2011 and a smaller decrease in accounts payable.

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

Cash Flows from Financing Activities
For the year ended December 31, 2012, cash flows generated by financing activities totalled $312.4 million ($326.9 million in 2011). This results mainly from a $4.8 million net increase in dividends paid to preferred and common shareholders and a $17.5 million smaller increase in long-term debt (net increase of long-term debt of $199.2 million in 2012 compared with $216.7 million in 2011), partly offset by a $7.7 million net increase in issuance of common and preferred shares.

Use of Financing Proceeds

For the years ended December 31	2012	2011
Proceeds from issuance of long-term debt	405,657	270,117
Net proceeds from issuance of common shares	114,571	155,721
Net proceeds from issuance of Series C Preferred shares	48,350	—
Proceeds from exercise of share options	507	—
	569,085	425,838
Cash acquired on business acquisitions	—	4,943
Business acquisitions	(68,635)	(160,844)
Additions to property, plant and equipment	(186,760)	(178,896)
Additions to intangible assets	(1,929)	(3,469)
Additions to project development costs	(8,146)	(31,726)
Additions to other long-term assets	(27,892)	(724)
Loans to partners	(23,444)	1,000
Funds invested in the reserves funded from long-term debt	(7,601)	—
Payment of deferred financing costs	(4,248)	(5,983)
Repayment of long-term debt	(202,245)	(47,475)
Use of financing proceeds	(530,900)	(423,174)
Contribution to working capital	38,185	2,664

During the year ended December 31, 2012, the Corporation borrowed $405.7 million to pay for the construction of the Kwoiek Creek, Northwest Stave River, Gros-Morne and Stardale projects and to repay the Glen Miller long-term debt. Proceeds of $163.4 million from the issuance of shares and exercise of options were used to pay for the acquisitions of the Brown Lake and Miller Creek hydroelectric facilities and the $25.0 million deposit (included in additions to other long-term assets) for the potential acquisition of any Hydromega assets, to reduce drawings under the revolving term credit facility and to repay long-term debt of an amount of $202.2 million. The contribution to working capital includes the funds from the Kwoiek Creek loan that had not been used as at December 31, 2012. During the corresponding period of 2011, the Corporation borrowed $270.1 million and issued common shares for $155.7 million to pay for the Cloudworks Acquisition and additions to assets and to repay long-term debt.

Cash Flows from Investing Activities
For the year ended December 31, 2012, cash flows used by investing activities amounted to $357.8 million ($377.2 million in 2011). During this period, business acquisitions accounted for a $68.6 million outflow ($160.8 million in 2011), additions to property, plant and equipment accounted for a $186.8 million outflow ($178.9 million in 2011), additions to project development costs for an $8.1 million outflow ($31.7 million in 2011), additions to intangible assets and other long-term assets for a combined $29.8 million outflow ($4.2 million in 2011), due mainly to the $25.0 million deposit for the potential acquisition of any Hydromega assets, investment in the reserves for a net outflow of $6.6 million (net inflow of $8.0 million in 2011) and an increase in restricted cash and short-term investments for a $34.4 million outflow ($15.5 million in 2011). The increase in restricted cash and short-term investments is attributable mainly to the Kwoiek Creek loan; funds will be used to pay construction costs as construction progresses. Cash acquired concurrently with the Cloudworks Acquisition accounted for a $4.9 million inflow in 2011.

Cash and Cash Equivalents
For the year ended December 31, 2012, the Corporation generated $16.8 million in cash and cash equivalents ($6.8 million used in 2011) as a net result of its operating, financing and investing activities.

As at December 31, 2012, the Corporation had cash and cash equivalents amounting to $52.0 million ($35.3 million as at December 31, 2011).

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

DIVIDENDS

The following are the dividends that were declared by the Corporation:

For the years ended December 31	2012	2011
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 common shares	50,693	43,990
Dividends declared on common shares ($ per share)	0.58	0.58

The following are the dividends that will be paid by the Corporation on April 14, 2013:

Date of announcement	Record date	Payment date	Dividends per common share ($)	Dividend per Preferred Series A share ($)	Dividend per Preferred Series C share[1] ($)
3/14/2013	3/28/2013	4/15/2013	0.1450	0.3125	0.4923

1. This initial dividend reflects the dividend accruing since the closing date of the Series C Preferred Share offering of December 11, 2012.

FINANCIAL POSITION

Assets

As at December 31, 2012, the Corporation had $2.3 billion in total assets ($2.0 billion as at December 31, 2011). This increase is due primarily to the following:

- a net increase in cash and cash equivalents and restricted cash and short-term investments from $88.7 million as at December 31, 2011, to $139.9 million as at December 31, 2012, due mainly to the Kwoiek Creek loan, which funds have been received and are being used as construction progresses;
- an increase in accounts receivable from $36.9 million to $50.8 million due mainly to the Hydro-Québec receivables for the reimbursement for the Gros-Morne substation, which was recorded under other long-term assets in the previous period;
- an increase in loans to partners from nil to $23.4 million, as explained in the "Working Capital" section below;
- an increase in reserve accounts from $42.2 million to $48.7 million due mainly to the Brown Lake and Miller Creek hydroelectric facilities and Montagne-Sèche;
- an increase in property, plant and equipment from $1.3 billion to $1.5 billion due mainly to the acquisition of the Brown Lake and Miller Creek hydroelectric facilities, to the construction of Stardale and Gros-Morne and to the Development Projects under construction;
- an increase in project development costs from $98.0 million to $107.2 million due mainly to the Development Projects under permit phase; and
- an increase in other long-term assets from $18.0 million to $31.3 million due mainly to the $25.0 million deposit for the potential acquisition of any Hydromega assets, partly offset by the reclassification to accounts receivable of the Gros-Morne substation receivables.

These increases were partly offset by a decrease in deferred tax assets from $24.5 million to $5.8 million due to an internal reorganization, which resulted in a reclassification to deferred tax liabilities.

Working Capital

As at December 31, 2012, working capital was positive at $83.4 million with a working capital ratio of 1.60:1.00. As at December 31, 2011, working capital was positive at $50.1 million with a working capital ratio of 1.60:1.00. Although total current assets increased from $133.1 million to $223.3 million, there was no variation in the working capital ratio over the last year as total current liabilities increased from $83.0 million to $139.8 million.

In view of these ratios, the Corporation considers its current level of working capital to be sufficient to meet its needs. In the third quarter of 2012, the Corporation exercised a portion of the accordion feature on its revolving term credit facility, increasing its borrowing capacity from $350.0 million to $425.0 million. As at December 31, 2012, the Corporation had drawn US$13.9 million and $189.8 million as cash advances and $21.1 million had been used for issuing letters of credit.

As part of the Cloudworks Acquisition, the Corporation maintains restricted cash and short-term investments, which amounted to $53.4 million as at December 31, 2011. As at December 31, 2012, restricted cash and short-term investment amounted to $87.8 million, of which $81.2 million was related to the Kwoiek Creek loan.

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

Accounts receivable increased from $36.9 million as at December 31, 2011, to $50.8 million as at December 31, 2012. The increase stems mainly from Hydro-Québec receivables for the reimbursement for the Gros-Morne substation.

In the fourth quarter of 2012, the parent of the Harrison Operating Facilities distributed $46.9 million to its partners. The funds were distributed in the form of loans to the Corporation and its partners. The loans of $23.4 million were presented as loans to partners as at December 31, 2012. It is expected that during the year of 2013, these loans will be reimbursed directly from a distribution from the parent of the Harrison Operating Facilities and a corresponding decrease in non-controlling interests will be recorded with no impact to cash flows.

Accounts payable and accrued liabilities increased from $26.6 million as at December 31, 2011, to $41.3 million as at December 31, 2012, due mainly to the construction of the Kwoiek Creek hydroelectric facility.

Derivative financial instruments included in current liabilities decreased from $20.3 million as at December 31, 2011, to $17.9 million as at December 31, 2012. The decrease stems mainly from the settlement of the Kwoiek Creek bond forwards, partly offset by the increase of unrealized net loss on derivative financial instruments related to the Northwest Stave River bond forwards, and Stardale swap, which became effective in September 2012.

The current portion of long-term debt relates to the payments due on the credit facilities and bonds of some Operating Facilities. The increase from $19.5 million as at December 31, 2011, to $64.5 million as at December 31, 2012, is due mainly to the upcoming Carleton loan refinancing and Stardale loan, which principal reimbursement started in September 2012. The Carleton loan will mature in November 2013 and the Corporation expects to refinance the outstanding balance by that date.

Reserve Accounts

	December 31, 2012	December 31, 2011
Hydrology/wind reserve	46,154	39,045
Major maintenance reserve	2,595	3,109
Total	48,749	42,154

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 $1.5 billion in property, plant and equipment as at December 31, 2012, compared with $1.3 billion as at December 31, 2011. This increase stems mainly from the acquisition of the Brown Lake and Miller Creek hydroelectric facilities, the construction of Stardale and Gros-Morne, and Development Projects under construction, partly offset by depreciation.

Intangible Assets
Intangible assets consist of various PPAs, permits and licences. They also include the extended warranty for the Carleton, Montagne Sèche and Gros-Morne wind farm turbines. The Corporation reported $440.5 million in intangible assets as at December 31, 2012, a decrease from the $441.3 million reported as at December 31, 2011. This decrease stems from amortization. Intangible assets, excluding $5.1 million related to the wind farms' extended warranty, are amortized using the straight-line method over 11- to 40-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, 2012, the Corporation had $107.2 million in project development costs ($98.0 million as at December 31, 2011). This increase is due to the Development Projects under permit phase.

Goodwill
The Corporation had $8.3 million in goodwill as at December 31, 2012 (same as at December 31, 2011). Goodwill is tested for impairment annually or more frequently when there is indication that it may be impaired. No impairment was recognized for the year ended December 31, 2012.

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 for which construction has been completed but costs remained to be paid. As at December 31, 2012, the Corporation had $13.1 million in accrual for acquisition of long-term assets ($41.3 million as at December 31, 2011). This decrease stems mainly from final drawings under the Stardale and Montagne Sèche loans, drawings on Kwoiek Creek loan and drawings under the revolving term credit facility for Gros-Morne, partly offset by Northwest Stave, Viger-Denonville and the Development projects under permit phase.

Long-Term Debt
As at December 31, 2012, long-term debt totalled $1.3 billion ($1.0 billion as at December 31, 2011). The increase in long-term debt results mainly from the new Kwoiek Creek construction loan, final drawings under the Stardale and Montagne Sèche loans and net drawings under the revolving credit term facility, partly offset by the repayment of the $13.3 million Glen Miller term loan in the first quarter of 2012 and by scheduled long-term debt repayments of $20.5 million.

Since the beginning of the 2012 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)

The Corporation had the following long-term debts outstanding as at December 31, 2012:

	Maturity		December 31, 2012	December 31, 2011
Revolving credit term facility		i)		
Prime rate advances	2016		20	20
Bankers' acceptances	2016		189,780	164,780
LIBOR advances, US$13,900	2016		13,829	14,136
Term loans				
Glen Miller, floating rate	2013	ii)	—	13,500
Carleton, floating rate	2013	iii)	43,412	46,298
Umbata Falls, floating rate	2014	iv)	23,392	23,885
Fitzsimmons Creek, floating rate	2016	v)	22,133	22,458
Hydro-Windsor, fixed rate	2016	vi)	4,145	5,027
Montagne-Sèche, floating rate	2016	vii)	30,021	26,200
Rutherford Creek, fixed rate	2024	viii)	48,634	50,000
Ashlu Creek, floating rate	2025	ix)	100,810	102,669
L'Anse-à-Valleau, floating rate	2026	x)	43,515	45,706
Stardale, floating rate	2030	xi)	110,630	73,706
Kwoiek Creek, fixed rate subordinated term loan		xii)	150	150
Kwoiek Creek, fixed rate		xiii)	168,500	—
Other loans with various maturities and interest rates	2013-2017	xiv)	222	73
Bonds				
Harrison Operating Facilities, real return	2049	xv)	225,137	226,338
Harrison Operating Facilities, fixed rate	2049	xvi)	213,738	215,570
Harrison Operating Facilities, real return	2049	xvii)	26,760	26,484
Deferred financing costs			(10,727)	(7,488)
			1,254,101	1,049,512
Current portion of long-term debt			(64,452)	(19,475)
			1,189,649	1,030,037

i) a $425.0 million revolving credit term facility secured by a first-ranking hypothec on Innergex assets and by various security interests granted by some of its subsidiaries. The facility will mature in 2016 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, 2012, $203.6 million was due under this facility and $21.1 million was used for the issuance of letters of credit; thus the unused and available portion of the revolving credit term facility totalled $200.2 million. As at December 31, 2012, the all-in interest rate was 5.23% after accounting for the interest rate swaps;

ii) a non-recourse term loan maturing in 2013 secured by the Glen Miller hydroelectricity facility. The loan was reimbursed in the first quarter of 2012;

iii) a non-recourse term loan secured by the Corporation's 38% interest in the Carleton wind farm. The loan's quarterly principal payments are based on an 18.5-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2012, the all-in effective interest rate was 4.84% after accounting for the interest rate swap. The loan will mature in November 2013 and the Corporation expects to refinance it by that date;

iv) a non-recourse term loan maturing in 2014 secured by the Corporation's 49% ownership interest in Umbata Falls hydroelectric facility. The loan's quarterly principal payments are based on a 25-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2012, the all-in interest rate was 5.28% after accounting for the interest rate swap;

v) a non-recourse term loan maturing in 2016 secured by the Fitzsimmons Creek hydroelectric facility. The loan's monthly principal payments are based on a 30-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2012, the all-in effective interest rate was 3.98%;

vi) a non-recourse term loan maturing in 2016 secured by the Hydro-Windsor hydroelectric facility. The loan is repayable by monthly blended payments of principal and interest totalling $105. The loan bears interest at an effective fixed interest rate of 8.25%;

vii) a non-recourse term loan, which was converted from a construction loan on August 16, 2012. The loan is secured by the Corporation's 38% interest in the Montagne Sèche wind farm and matures in 2016. The loan's quarterly principal payments began on March 31, 2012, and is based on an 18.5-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2012, the all-in effective interest rate was 6.72% after accounting for the interest rate swap;

viii) a non-recourse term loan maturing in 2024 secured by the Rutherford Creek hydroelectric facility. The debt is repayable in monthly blended payments of principal and interest totalling $511 since July 1, 2012. The loan bears interest at a fixed rate of 6.88%;

ix) a non-recourse term loan maturing in 2025 secured by the Ashlu Creek hydroelectric facility. The loan's quarterly principal payments are based on a 25-year amortization period. The loan bears interest at the BA rate or prime-rate plus an applicable credit margin. As at December 31, 2012, the all-in effective interest rate was 6.04% after accounting for the interest rate swaps;

x) a non-recourse term loan maturing in 2026 secured by the Corporation's 38% interest in the L'Anse-à-Valleau wind farm. The loan's quarterly principal payments are based on an 18.5-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2012, the all-in interest rate was 5.93% after accounting for the interest rate swap;

xi) a non-recourse term loan, which was converted from a construction loan on July 31, 2012. The loan is secured by the Stardale solar farm and will mature in 2030. The loan's quarterly principal payments began on September 30, 2012 and is based on an 18-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2012, the all-in effective interest rate was 5.79%;

xii) 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 project agreements, 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 $44.8 million as at December 31, 2012;

xiii) a $168.5 million non-recourse construction loan, of which $94.6 million had been used as at December 31, 2012, to pay for project costs while the difference is held in restricted cash to pay for future costs. The loan is secured by the Kwoiek Creek hydroelectric facility. The loan bears a fixed interest rate of 5.08%; it will convert to a 39-year term loan following the start of the project's commercial operation and will amortize over a 36-year period three years later;

xiv) Other loans with various maturities and interest rates;

xv) 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 $5,790 before CPI adjustment. On December 1, 2031, the payment amount decreases to $4,481 before CPI adjustment. 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 not-seasonally adjusted CPI. As at December 31, 2012, the all-in effective interest rate was 5.20%;

xvi) 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 $8,072. On December 1, 2031, the payment amount decreases to $6,724. The bond bears interest at an effective fixed interest rate of 6.66%;

xvii) a junior real return bond maturing in 2049 secured by the Harrison Operating Facilities but second ranking to the bonds described in xv) and xvi). The bond is repayable in quarterly interest payments of $291 before CPI adjustment. On June 1, 2017, the quarterly payments increase to $389 before CPI adjustment and include principal repayment until maturity. 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 not-seasonally adjusted CPI. As at December 31, 2012, the all-in effective interest rate was 6.20%.

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. Since the beginning of the 2012 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.

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, 2012, the debt portion of the Convertible Debentures was $79.7 million and the equity portion was $1.3 million ($79.5 million and $1.3 million respectively as at December 31, 2011).

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 $1,000 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.

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-3 (low) by DBRS.

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.

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 initial dividend will be $0.4923 per share and will be payable on April 15, 2013.

(in thousands of Canadian dollars, except as noted, and amounts 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.

The Series C Preferred Shares are rated P-3 by S&P and Pfd-3 (low) by DBRS.

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.

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 and to the risk of rising foreign currencies on its equipment purchases. While Derivatives are entered into with major financial institutions rated BBB or better by S&P, the evolution of the economic situation may affect some of the Corporation's counterparties. The Corporation nevertheless considers the risk of illiquidity to be low, as current interest rate swap valuation results in amounts being treated as Innergex liabilities owed to the counterparties. The forward foreign exchange contracts are treated as Innergex assets.

For a long-term debt subject to variable interest rates, Innergex will use bond forward contracts and interest rate swaps. For equipment purchases in a currency other than Canadian dollars, the Corporation will use forward foreign exchange contracts. These measures protect the economic return of the related Operating Facility or Development Project. The Corporation does not intend to settle its Derivatives before maturity. The Corporation does not own or issue any Derivatives for speculation purposes. The Corporation does not use hedge accounting to account for its Derivatives.

Taken together, the bond forward and swap contracts shown in the following table allow the Corporation to eliminate the risk of interest rate increases in actual and planned long-term debt ($514.3 million and $52.5 million respectively). As at December 31, 2012, interest rate swaps related to outstanding debts combined with the $532.5 million in existing fixed-rate debts and the $79.7 million in convertible debentures mean that 95% of outstanding debts are protected from interest rate increases.

	Maturity	Early termination option	December 31, 2012	December 31, 2011
Bond forwards, from 2.00% to 2.88%	2013	None	52,500	137,500
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 swap, 4.41%	2018	2013	30,000	30,000
Interest rate swap, 4.27%	2018	2013	52,600	52,600
Interest rate swap, from 4.83% to 4.93%, amortizing	2026	None	43,514	45,705
Interest rate swap, from 3.35% to 3.45%, amortizing	2027	2013	42,792	45,605
Interest rate swap, from 3.74% to 3.85%, amortizing	2030	None	101,780	101,996
Interest rate swap, 4.22%, amortizing	2030	2016	30,021	31,690
Interest rate swap, 4.25%, amortizing	2031	2016	47,323	49,940
Interest rate swap, from 3.98% to 4.11%, amortizing	2034	None	23,392	23,885
Interest rate swaps, from 4.61% to 4.70%, amortizing	2035	2025	105,031	107,111
Interest rate swap, 2.85%, amortizing	2041	2016	19,853	20,100
			566,806	664,132

As at December 31, 2012, the forward foreign exchange contracts allow the Corporation to eliminate the risk of an Euro appreciation versus the Canadian dollar on equipment purchases related to the Viger-Denonville project of a total amount of €6.8 million. The forward foreign exchange contracts will mature in 2013.

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

Derivatives had a net negative value of $81.5 million at December 31, 2012 (negative $91.4 million at December 31, 2011). This favourable difference is due mainly to settlement of the Kwoiek Creek bond forward contracts and the increase in benchmark interest rates since the end of 2011. The estimated impact of a 0.1% interest rate increase would decrease the bond forward contracts and interest rate swap-related liability by $5.4 million. Conversely, a 0.1% interest-rate decrease would increase the bond forward contracts and interest rate swap-related liability by $5.5 million. The estimated impact of an increase of the Canadian dollar value of $0.01 against €1.00 would decrease the forward foreign exchange-related asset by $0.1 million. Conversely, a decrease of the Canadian dollar value of $0.01 against €1.00 would increase the forward foreign exchange-related asset by $0.1 million.

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 or the forward foreign exchange-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 or the forward foreign exchange-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 or the forward foreign exchange-based discount rate. As at December 31, 2012, all bond forward contracts and interest rate swaps were accounted for as liabilities and credit spreads from 0.06% to 3.11% were added to the discount rates. All forward foreign exchange contracts were accounted for as assets and credit spreads of up to 0.01% were added to the discount rates. The estimated credit-adjusted values of the Derivatives are subject to changes in credit spreads of Innergex and its counterparties.

As at December 31, 2012, the fair market value of the derivative financial instruments related to some PPAs with Hydro-Québec was positive at $8.4 million ($10.0 million as at December 31, 2011). These instruments represent the value attributed to minimum inflation clauses of 3% per year included in these PPAs.

Deferred Income Taxes
The tax impact of temporary differences may result in future tax assets or liabilities. As at December 31, 2012, the Corporation's net deferred tax liability was $133.4 million, compared with a net deferred tax liability of $116.0 million as at December 31, 2011. This increase results mainly from the business acquisitions, the reclassification from deferred tax assets to deferred tax liabilities following a reorganization and the earnings before income taxes recognized for the year ended December 31, 2012.

Off-Balance-Sheet Arrangements
As at December 31, 2012, the Corporation had issued letters of credit totalling $33.1 million to meet its obligations under its various PPAs and other agreements. Of this amount, $21.1 million was issued under its revolving credit term facility and the remainder under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $44.8 million in corporate guarantees to support the construction of the Gros-Morne and Viger-Denonville wind farms, the performance of the Brown Lake and Miller Creek hydroelectric facilities and some bond forward contracts.

Shareholders' Equity
As at December 31, 2012, the shareholders' equity of the Corporation totalled $687.9 million, including $107.6 million of non-controlling interests, compared with $579.1 million, including $114.4 million of non-controlling interests, as at December 31, 2011. The increase in total shareholders' equity stems mainly from the share capital issued, partly offset by dividends declared.

Contractual Obligations

As at December 31, 2012	Total	Under 1 year	1 to 3 years	4 to 5 years	Thereafter
Long-term debt including convertible debentures	1,410,043	65,331	70,556	378,591	895,565
Interest on long-term debt and convertible debentures	989,499	69,956	132,891	110,486	676,165
Others	20,725	1,745	3,507	2,709	12,765
Purchase (Contractual) obligations[1]	111,881	80,056	8,348	5,760	17,717
Total contractual obligations	2,532,148	217,088	215,302	497,546	1,602,212

1. Purchase obligations are derived mainly from turbine supply agreements and engineering, procurement and construction contracts.

Contingencies
Cloudworks
The Cloudworks Acquisition provides for the potential payment of additional amounts to the vendors over a period of more than 40 years commencing on April 4, 2011, 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 intended to provide for the potential sharing of the value created if the Harrison Operating Facilities and projects under development perform better than the Corporation's expectations and if Prospective Projects are developed.

The maximum aggregate amount of all deferred payments under the Cloudworks Acquisition is limited to a present value of $35 million. For the purpose of applying such a maximum aggregate amount, the amount of any deferred payments made is discounted to its present value by applying a mutually agreed-upon discount rate per annum. At any time during the five-year period after April 4, 2011, the Corporation has the right to cancel all of its obligations to make deferred payments by making a one-time payment of the amount by which the maximum aggregate amount of deferred payments ($35 million) exceeds the present value of any deferred payments (discounted to their present value amounts by applying an agreed discount rate per annum) made prior to the exercise of such right by the Corporation.

Stardale
In connection with the acquisition of the Stardale project, the Corporation agreed to pay contingent considerations based on future events for a period of three years beginning April 20, 2011. These contingent considerations provide for a potential sharing of the value created if Stardale benefits from a return better than the Corporation's initial expectation agreed upon with the seller as at the acquisition date.

SEGMENT INFORMATION
Geographic Segments
As at December 31, 2012, the Corporation had 21 hydroelectric facilities, five wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2012, operating revenues generated by the Horseshoe Bend hydroelectric facility in the United States totalled $3.4 million ($2.7 million in 2011), representing contributions of 2% (same in 2011) to the Corporation's consolidated operating revenues for this period.

Operating Segments
As at December 31, 2012, 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 farm and solar facilities to publicly owned utilities. Through its site development segment, Innergex analyses 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, 2012. 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 power or solar power generation segments are accounted for at cost.

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

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

	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
For the year ended December 31, 2012					
Power generated (GWh)	1,579,222	535,854	33,374	—	2,148,450
Operating revenues	123,626	45,558	11,676	—	180,860
Expenses:					
Operating expenses	20,640	7,960	533	—	29,133
General and administrative expenses	5,451	2,252	278	1,751	9,732
Prospective project expenses	—	—	—	4,412	4,412
Adjusted EBITDA	97,535	35,346	10,865	(6,163)	137,583
For the year ended December 31, 2011					
Power generated (GWh)	1,552,846	352,580	—	—	1,905,426
Operating revenues	117,342	30,918	—	—	148,260
Expenses:					
Operating expenses	18,174	6,052	—	—	24,226
General and administrative expenses	4,297	1,987	—	4,081	10,365
Prospective project expenses	—	—	—	2,473	2,473
Adjusted EBITDA	94,871	22,879	—	(6,554)	111,196

	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
As at December 31, 2012					
Goodwill	8,269	—	—	—	8,269
Total assets	1,322,173	423,634	139,222	438,924	2,323,953
Total liabilities	836,859	383,435	144,555	271,172	1,636,021
Acquisition of property, plant and equipment during the year	612	3,682	153	169,449	173,896
As at December 31, 2011					
Goodwill	8,269	—	—	—	8,269
Total assets	1,310,207	387,099	—	336,103	2,033,409
Total liabilities	838,575	324,270	—	291,448	1,454,293
Acquisition of property, plant and equipment during the year	1,305	484	—	192,396	194,185

Hydroelectric Generation Segment
For the year ended December 31, 2012, this segment produced 2% less power than the LTA, resulting in operating revenues of $123.6 million. The production level for the year ended December 31, 2012, was due mainly to lower than anticipated water flows at the segment's British Columbia facilities in the first and fourth quarters of 2012 and at the segment's Ontario and Quebec facilities in the third quarter of 2012.

For the year ended December 31, 2011, the hydroelectric generation segment produced 3% more power than the LTA respectively due to better than anticipated hydrologic conditions at most of the segment's facilities, resulting in operating revenues of $117.3 million.

For the year ended December 31, 2012, higher revenues in United States ($0.6 million), additional revenues from the acquisition of the Brown Lake and Miller Creek facilities ($1.0 million) and revenues for the first quarter of 2012 from the Harrison Operating Facilities ($5.2 million), compared with none for the corresponding period in 2011 resulted in higher revenues, partly offset by lower production in British Columbia, Ontario and Quebec.

The increase in total assets since December 31, 2011, is attributable mainly to the acquisition of the Brown Lake and Miller Creek hydroelectric facilities, partly offset by depreciation and amortization of property, plant and equipment as well as intangible assets.

The decrease in total liabilities since December 31, 2011, is attributable mainly to scheduled repayment of long-term debt, partly offset by an increase in deferred tax liabilities related to the acquisition of the Brown Lake and Miller Creek hydroelectric facilities.

Wind Power Generation Segment
For the year ended December 31, 2012, the wind power generation segment produced 6% less power than the LTA, resulting in operating revenues of $45.6 million. This lower performance level is due to the 42-day period during which Gros-Morne Phase I was halted and to the lower than anticipated wind regime at all the wind farms except the Montagne Sèche wind farm.

For the year ended December 31, 2011, the wind power generation segment produced 7% less power than the LTA due to lower than anticipated wind conditions at all the wind farms, resulting in operating revenues of $30.9 million. The difference in operating revenues stems mainly from the Montagne Sèche and Gros-Morne wind farms which generated $15.7 million for the year ended December 31, 2012, compared with none for the corresponding period of 2011, partly offset by lower production at the Carleton and L'Anse-à-Valleau wind farms.

Total assets have increased since December 31, 2011, due mainly to Gros-Morne, partly offset by depreciation and amortization of property, plant and equipment as well as intangible assets.

The increase in total liabilities since December 31, 2011, is attributable mainly to the transfer of the Gros-Morne II long-term debt, partly offset by scheduled repayment of long-term debt.

Solar Power Generation Segment
This new segment was added after the start of commercial operation of the Stardale solar farm on May 15, 2012. For the year ended December 31, 2012, the solar power generation segment produced 6% more power than expected, resulting in operating revenues of $11.7 million.

Site Development Segment
For the year ended December 31, 2012, a greater business emphasis on Prospective Projects largely explains the increase in prospective project expenses compared with the same period in 2011. This factor also explains the decrease in the general and administrative expenses compared with the same period in 2011.

The increase in total assets since December 31, 2011, results mainly from the Development Projects, in particular the Kwoiek Creek and Northwest Stave River projects, partly offset by the transfer of Stardale assets to the solar power generation segment.

The decrease in total liabilities since December 31, 2011, is attributable mainly to the transfer of the Stardale and Gros-Morne II long-term debts and to the net proceeds from issuance of shares that were partly used to reduce drawings under the revolving term credit facility, partly offset by Development Projects, in particular the Kwoiek Creek and Northwest Stave River projects.

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 disclosure 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 and intangible assets, deferred income taxes as well as the fair value of financial assets and liabilities, including derivative financial instruments. 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. Other significant accounting policies are listed in Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2012.

ACCOUNTING CHANGES

AMENDMENTS TO IFRS AFFECTING PRESENTATION AND DISCLOSURE ONLY

IAS 1 - Presentation of Items of Other comprehensive income

The International Accounting Standards Board ("IASB") issued amendments to IAS 1 Presentation of Financial Statements to split items of other comprehensive income between those that are reclassified to earnings and those that are not.

On June 16, 2011, the IASB issued amendments to IAS 1, Presentation of Financial Statements, which require entities to group together items within Other Comprehensive Income (“OCI”) that may be reclassified to the profit or loss section of the income statement and to separately group together items that will not be reclassified to the profit or loss section of the income statement. The amendments also reaffirm existing requirements that profit or loss and OCI should be presented as either a single statement or two consecutive statements. The amendments are effective for financial years commencing on or after July 1, 2012.

In May 2012, the IASB issued further amendments to IAS 1, Presentation of Financial Statements which are effective for annual periods beginning on or after January 1, 2013 with early application permitted. IAS 1 requires an entity that changes accounting policies retrospectively, or makes a retrospective restatement or reclassification to present a statement of financial position as at the beginning of the preceding period. The amendments to IAS 1 clarify that an entity is required to present a third statement of financial position only when the retrospective application, restatement or reclassification has a material effect on the information in the third statement of financial position and that related notes are not required to accompany the third statement of financial position.

The Corporation has reviewed this standard and it will have no impact on its results of operations and financial position.

NEW AND REVISED IFRS IN ISSUE 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.

The standard will be effective for annual periods beginning on or after January 1, 2015, with earlier adoption permitted. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 10 - Consolidated Financial Statements

The IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation has reviewed this standard and it has no impact on its results of operations and financial position.

IFRS 11 - Joint arrangements

IFRS 11 deals with how a joint arrangement, of which two or more parties have joint control, should be classified. Under IFRS 11, joint arrangements are classified as joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangements. Joint ventures under IFRS 11 are required to be accounted for using the equity method of accounting whereas jointly controlled entities can be accounted for using the equity method of accounting or proportional consolidation.

Several investments in associates and joint ventures are consolidated in the Corporation under IFRS. These investments are either fully consolidated or proportionately consolidated. Under the IFRS 11 revised standard, some of these investments might have to be accounted for as investments on the consolidated statements of financial position with their results recognized as share of net earnings of a joint venture or an investee.

The effective date for the application of the revised standard is January 1, 2013. The Corporation has reviewed this standard and the application of IFRS 11 will result in changes in the accounting method of the joint ventures that will be accounted for using the equity method. Consequently the balances of each line item on the consolidated statements of financial position and the consolidated statements of earnings are expected to change significantly.

IFRS 12 - Disclosure of Interests in Other Entities
The IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires a company to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation has reviewed this standard and the impact will result in more extensive disclosures but will not have any impact on the amounts in the financial statements.

IFRS 13 - Fair Value Measurement
The IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation has reviewed this standard and it should not have any impact on its results of operations and financial position.

IAS 28 (2011) - Investments in Associates and Joint Ventures
IAS 28 was amended in 2011 to prescribe the accounting for investments in associates and sets out the application of the equity method when accounting for investments in associates and joint ventures. IAS 28 is effective for annual periods beginning on or after January 1, 2013. The Corporation has reviewed the impact of this amendment to IAS 28 and the impact will result in changes in accounting method for Umbata Falls, L.P. and Viger-Denonville, L.P. joint ventures that will have to be accounted for using the equity method.

RISKS AND UNCERTAINTIES
The Corporation is exposed to various business 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 Annual Information Form for the year ended December 31, 2012. However, additional risks and uncertainties that are not presently known to the Corporation or that are currently believed to be immaterial may adversely affect the Corporation's business.

Execution of Strategy
The Corporation's strategy for building shareholder value is: (i) to acquire or develop 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. However, 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 successful execution of a value investment strategy requires careful timing and business judgment, as well as the resources to complete the development of power generating facilities. The Corporation may 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 new facilities and the development of the Development Projects and the Prospective Projects and other capital expenditures will be financed out of cash generated from the Corporation's operating facilities, borrowing and/or sales 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 or maintain existing project facilities and remain in business would be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion. There are a substantial number of 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.

The Corporation's capital-raising efforts could involve the issuance and sale of additional common shares or of 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 important 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 energy generated by the Corporation's hydroelectric facilities is dependent upon the availability of water flows. There is no certainty that the long-term availability of such resources will remain unchanged. The Corporation's revenues may be significantly affected by events that impact the hydrological conditions of the Corporation's hydroelectric project facilities, such as low and high water flows within the watercourses on which the Corporation's hydroelectric facilities are located. In the event of severe flooding, the Corporation's hydroelectric facilities may be damaged. Similarly, the amount of energy generated by the Corporation's wind power facilities will be dependent upon the availability of wind, which is naturally variable. A reduced or increased amount of wind at the location of one of the wind power project facilities over an extended period may reduce the production from such facility and may reduce the Corporation's revenues and profitability. Finally, the amount of energy to be generated by the Corporation's solar power projects will depend on the availability of solar radiation, which is naturally variable. A reduced or increased amount of solar radiation at the location of one of the solar farm projects over an extended period may reduce the production from such facility and may reduce the Corporation's revenues and profitability.

Construction Costs Over-runs and Design

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. A number of factors which could cause such delays or cost overruns include, but are not limited to, permitting delays, construction pricing escalation, changing engineering and design requirements, the performance of contractors, labour disruptions, adverse weather conditions and the availability of financing. Even when complete, a facility may not operate as planned due to design or manufacturing flaws, which may not all be covered by warranty. Mechanical breakdown could occur in equipment after the warranty period has expired, 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 respective PPA, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related 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) and the requirements of licenses, permits and other approvals will 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 and 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 operations and/or result in additional material expenditures. As a consequence, 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 construction and development of new power generating facilities. These facilities have greater uncertainty surrounding future profitability than existing operating facilities with established track records. In some cases, many factors affecting costs have not yet been determined, 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 development of its new facilities. In the event that some of these power generating facilities are not completed or do not operate to the expected 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. The failure to obtain or delays in obtaining all necessary licenses, approvals or permits, including renewals thereof or modifications thereto, could result in construction of the Development Projects or the Prospective Projects being delayed or not being completed. There can be no assurance that any one Prospective Project will result in any actual operating facility.

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 construction, during construction and during and after the operation of the Development Projects. It is not possible to forecast the conditions imposed by such permits or the cost of any mitigating measures required by such permits.

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 respective PPA, penalty payments may be payable to the relevant purchaser by the Corporation. The payment of any such penalties by the Corporation could adversely affect its revenues and profitability.

Equipment Failure
The Corporation's facilities are subject to the risk of equipment failure due to 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 disruptions of power generation for other reasons, the Corporation's business, operating results, financial condition or prospects could be adversely affected.

Interest Rate and Refinancing Risk
Interest rate fluctuations are of particular concern to a capital-intensive industry such as the electric power business. 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: (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 of and interest on their indebtedness, thereby reducing funds available for future operations; (iii) certain of the Corporation's and its subsidiaries' borrowings will be at variable rates of interest, which exposes the Corporation and its subsidiaries to the risk of increased 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 guarantee 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 the Corporation's and its subsidiaries' business and 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 needed assets or take other actions the Corporation or its subsidiaries might otherwise consider appropriate or desirable.

Declaration of Dividends is at the Discretion of the Board
Holders of Common Shares, Series A Shares and Series C Shares do not have a right to dividends on such shares unless 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 for believing that (i) the Corporation is, or would after the payment be, unable to pay its liabilities as they become due, or (ii) the realizable value of the Corporation's assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares.

Securing New Power Purchase Agreements
Securing new PPAs, which is a key component of the Corporation's growth strategy, is a risk factor in light of the competitive environment faced by the Corporation. The Corporation expects to continue to enter into PPAs for the sale of its power, which PPAs are mainly obtained through participation in competitive Requests for Proposals 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 selected as power supplier following any particular Request for Proposals in the future or that existing PPAs will be renewed or will be renewed on equivalent terms and conditions upon the expiry of their respective terms.

ADDITIONAL INFORMATION 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.

QUARTERLY FINANCIAL INFORMATION

	For the three-month periods ended			
(in millions of dollars, unless otherwise stated)	Dec. 31, 2012	Sept. 30, 2012	June 30, 2012	Mar. 31, 2012
Power generated (MWh)	541,631	564,617	714,700	327,508
Operating revenues	48.5	47.5	56.0	28.8
Adjusted EBITDA	35.5	37.0	46.2	18.9
Unrealized net gain (loss) on derivative financial instruments	5.8	9.6	(28.0)	21.0
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)	0.01	(0.01)	(0.12)	0.10
Dividends declared on Series A 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

	For the three-month periods ended			
(in millions of dollars, unless otherwise stated)	Dec. 31, 2011	Sept. 30, 2011	June 30, 2011	Mar. 31, 2011
Power generated (MWh)	403,920	666,009	595,317	240,180
Operating revenues	33.1	50.5	43.8	20.8
Adjusted EBITDA	21.8	40.1	34.6	14.7
Unrealized net (loss) gain on derivative financial instruments	(19.6)	(40.5)	(10.9)	9.5
Net (loss) earnings	(21.0)	(21.6)	(6.8)	5.7
Net (loss) earnings attributable to owners of the parent	(13.9)	(26.2)	(6.5)	6.0
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.18)	(0.34)	(0.09)	0.08
Dividends declared on Series A Preferred Shares	1.1	1.1	1.1	1.1
Dividends declared on common shares	11.8	11.8	11.8	8.6
Dividends declared on common shares ($ per share)	0.145	0.145	0.145	0.145

Comparing the results for the most recent quarters makes apparent the seasonality that is characteristic of the Corporation's assets, i.e. that power generated, operating revenues and Adjusted EBITDA vary from quarter to quarter. As the Corporation's total average long-term production is 71% 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. Furthermore, solar irradiation is at its highest during the summer months and at its lowest during the winter months. 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. The production of the wind farms also partially compensates for this seasonality experienced by hydroelectric facilities, as wind regimes are generally best in the first quarter of a typical year.

By excluding non-recurring items, readers would expect that the net earnings (loss) attributable to owners of the parent and net earnings (loss) per share attributable to owners of the parent reflect this seasonality characteristic of run-of-river hydroelectric plants, of wind farms and of 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) attributable to owners of the parent and net earnings (loss) per share attributable to owners of the parent is change in the market value of derivative financial instruments. Historical analysis of net earnings (loss) attributable to owners of the parent and net earnings (loss) per share attributable to owners of the parent 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 and inflation rate fluctuations and do not have an impact on the Corporation's Adjusted EBITDA or finance costs.

Fourth Quarter Results

Operating Facilities

During the fourth quarter of 2012, the Corporation's Operating Facilities produced 541,631 MWh (403,920 MWh in 2011). This increase is essentially due to better water flows in Ontario and British Columbia, the acquisition of the Brown Lake and Miller Creek hydroelectric facilities and the addition of Stardale, Gros-Morne and Montagne Sèche.

Compared with the estimated long-term average, the Corporation produced 2% less energy than expected. The hydroelectric facilities' overall production was above its long-term average and the wind farms' production was lower than expected. Stardale solar farm was in line with its LTA.

Revenues

Revenues from operating activities totalled $48.5 million in the fourth quarter of 2012 ($33.1 million in 2011). This performance is due to additional revenues resulting from better water flows in Ontario and British Columbia, the acquisition of the Brown Lake and Miller Creek hydroelectric facilities and the addition of Stardale, Gros-Morne and Montagne Sèche.

Expenses
In the fourth quarter of 2012, the Corporation incurred $9.4 million in operating expenses ($8.0 million in 2011) related to the operation of the power producing facilities. This increase is due mainly to the Corporation's operating a greater number of facilities in 2012 than in 2011.

The Corporation also incurred general and administrative expenses of $1.8 million during the period ($2.5 million in 2011).

Prospective projects expense totalled $1.8 million during the fourth quarter of 2012 ($0.9 million in 2011). This increase reflects the efforts devoted by the Corporation to develop SOP projects in British Columbia and other projects in Quebec and Ontario.

The Corporation incurred $17.1 million in finance costs during the last quarter of 2012 ($15.3 million in 2011). This increase is due mainly to a larger amount of debt and to the Stardale loan, which was based on a floating rate in 2011, compared with a fixed rate in 2012. These elements were partly offset by lower inflation compensation interest.

The depreciation and amortization expense totalled $17.8 million in the fourth quarter of 2012 ($14.3 million in 2011). The difference is attributable mainly to the greater asset base resulting from the addition of Gros-Morne, Montagne Sèche and Stardale and from the acquisition of Brown Lake and Miller Creek hydroelectric facilities.

For the last quarter of 2012, the Corporation recorded a $5.8 million unrealized net gain on derivative financial instruments due mainly to the increase in benchmark interest rates since September 30, 2012. For the corresponding quarter of 2011, Innergex recorded an unrealized net loss on derivative financial instruments of $19.6 million due to a decrease in benchmark interest rates since September 30, 2011.

For the quarter ended in December 31, 2012, the provision for current income taxes totalled $0.4 million ($1.4 million in 2011). Innergex is able to minimize current income taxes due to its young pool of property, plant and equipment, which results in a substantial available unused capital cost allowance.

The Corporation recorded a provision for future income tax of $5.3 million in the fourth quarter of 2012 (income tax recovery of $6.9 million in 2011). This difference is due mainly to an unrealized net gain on derivative financial instruments in the fourth quarter of 2012 compared with an unrealized net loss on derivative financial instruments for the corresponding period in 2011. Higher revenues in the fourth quarter of 2012 compared with the same period in 2011, partly offset by increases in operating and prospective project expenses (net variation of $13.1 million), can also explain the variation.

Net Earnings (Loss)
The Corporation posted net loss and net earnings attributable to the owners of the parent of $0.6 million and $1.8 million respectively (basic and diluted net earnings of $0.01 per share) for the fourth quarter of 2012. For the corresponding period in 2011, net loss and net loss attributable to the owners of the parent totalled $21.0 million and $13.9 million respectively (basic and diluted net loss of $0.18 per share). This $20.4 million positive variation in net earnings (loss) is attributable mainly to a $15.4 million increase in operating revenues and a $25.4 million positive variation in the fair market value of derivative, partly offset by a $1.8 million increase in finance costs, a $3.6 million increase in depreciation and amortization and a $11.2 million unfavourable variation in income tax.

The basic and diluted per-share figures for the three-month period ended December 31, 2012, are based on a weighted average number of 93,614,376 and 93,772,572 commons shares respectively. 1,263,000 stock options were non-dilutive during the period concerned, as the average market price of the Corporation's common share was below the strike price. The other 1,473,684 options were dilutive as the average market price of the Corporation's common share was above the strike price. However, they were excluded from the per-share figure calculation, as the Corporation recognized a net loss for the three-month period ended December 31, 2012. Convertible Debentures were non-dilutive as the average market price was below the conversion price.

As at March 14, 2013, and December 31, 2012, the Corporation had a total of 93,964,093 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 December 31, 2011, it had 81,282,460 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares and 2,677,444 stock options outstanding.

SUBSEQUENT EVENTS

Viger-Denonville

On February 23, 2013, the Viger-Denonville wind farm project gave the engineering procurement and construction contractor a notice to proceed, which was shortly followed by the Certificate of Authorization to start construction given by the Ministère du Développement durable, de l'Environnement, de la Faune et des Parcs.

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 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 s.e.n.c.r.l., in accordance with **Canadian generally accepted auditing standards** and on the shareholders' behalf. Deloitte s.e.n.c.r.l. 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, CMA
Chief Financial Officer and
Senior Vice President

Innergex Renewable Energy Inc.

Longueuil, Canada, March 14, 2013

Deloitte.

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, 2012 and December 31, 2011, 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, 2012 and December 31, 2011, 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, 2012 and December 31, 2011 and its financial performance and its cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with International Financial Reporting Standards.

Deloitte s.e.n.c.r.l.

Montreal, Quebec
March 14, 2013

[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)

For the years ended	Notes	December 31, 2012	December 31, 2011
Revenues			
Operating		180,860	148,260
Expenses			
Operating	7	29,133	24,226
General and administrative		9,732	10,365
Prospective project expenses		4,412	2,473
Earnings before finance costs, income taxes, depreciation, amortization, other net expenses and unrealized net (gain) loss on derivative financial instruments		137,583	111,196
Finance costs	8	63,281	53,122
Other net expenses	9	15,527	2,693
Earnings before income taxes, depreciation, amortization and unrealized net (gain) loss on derivative financial instruments		58,775	55,381
Depreciation	17	43,902	31,177
Amortization	18	21,835	19,793
Unrealized net (gain) loss on derivative financial instruments		(8,342)	61,479
Earnings (loss) before income taxes		1,380	(57,068)
Provision (recovery) for income taxes :	12		
Current		1,970	464
Deferred		4,793	(13,828)
		6,763	(13,364)
Net loss		(5,383)	(43,704)
Net earnings (loss) attributable to:			
Owners of the parent		1,405	(40,547)
Non-controlling interests		(6,788)	(3,157)
		(5,383)	(43,704)
Weighted average number of common shares outstanding (in 000)	13	86,557	75,681
Basic net loss per share	13	(0.03)	(0.59)
Diluted weighted average number of common shares outstanding (in 000)	13	86,708	75,755
Diluted net loss per share	13	(0.03)	(0.59)

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

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

For the years ended	December 31, 2012	December 31, 2011
Net loss	(5,383)	(43,704)
Other items of comprehensive income (loss) that could be reclassified to profit or loss:		
Foreign exchange (loss) gain on translation of a self-sustaining foreign subsidiary	(90)	100
Deferred income tax recovery (provision)	12	(15)
Foreign exchange gain (loss) on the designated portion of the US dollar denominated debt used as hedge on the investment in a self-sustaining foreign subsidiary	104	(110)
Deferred income tax (provision) recovery	(13)	15
Total adjustments to net loss	13	(10)
Total comprehensive loss	(5,370)	(43,714)
Total comprehensive income (loss) attributable to:		
Owners of the parent	1,418	(40,557)
Non-controlling interests	(6,788)	(3,157)
	(5,370)	(43,714)

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(in thousands of Canadian dollars except as noted and amounts per share)

As at	Notes	December 31, 2012	December 31, 2011
Assets			
Current assets			
Cash and cash equivalents		52,048	35,279
Restricted cash and short-term investments	14	87,811	53,415
Accounts receivable	15	50,786	36,894
Reserve accounts	16	1,816	—
Income tax receivable	12	443	1,664
Derivative financial instruments	6	2,116	1,791
Loans to partners	32	23,444	—
Prepaid and others		4,789	4,074
		223,253	133,117
Reserve accounts	16	46,933	42,154
Property, plant and equipment	17	1,453,944	1,259,834
Intangible assets	18	440,498	441,262
Project development costs	19	107,165	98,042
Derivative financial instruments	6	6,698	8,248
Deferred tax assets	12	5,846	24,485
Goodwill	20	8,269	8,269
Other long-term assets		31,347	17,998
		2,323,953	2,033,409

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(in thousands of Canadian dollars except as noted and amounts per share)

As at	Notes	December 31, 2012	December 31, 2011
Liabilities			
Current liabilities			
Dividends payable to shareholders		14,643	12,848
Accounts payable and other payables	21	41,337	26,616
Income tax liabilities	12	1,541	2,835
Derivative financial instruments	6	17,855	20,287
Current portion of long-term debt	22	64,452	19,475
Contingent considerations	24	—	983
		139,828	83,044
Construction holdbacks		1,668	2,081
Derivative financial instruments	6	64,023	71,158
Accrual for acquisition of long-term assets		13,063	41,267
Long-term debt	22	1,189,649	1,030,037
Liability portion of convertible debentures	23	79,655	79,490
Contingent considerations	24	2,775	2,904
Asset retirement obligations	25	6,095	3,858
Deferred tax liabilities	12	139,265	140,454
		1,636,021	1,454,293
Shareholders' equity			
Common share capital	26 a)	120,500	1
Preferred shares	26 c)	131,069	82,589
Contributed surplus from reduction of capital on common shares	26 e)	656,281	656,281
Share-based payment		1,511	1,361
Equity portion of convertible debentures	23	1,340	1,340
Deficit		(330,621)	(277,083)
Accumulated other comprehensive income		241	228
Equity attributable to owners		580,321	464,717
Non-controlling interests		107,611	114,399
Total shareholders' equity		687,932	579,116
		2,323,953	2,033,409

Commitments and contingencies (see Note 30).

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

For the year ended December 31, 2012	Number of common shares (In 000's)	Common share capital account	Preferred shares	Contributed surplus from reduction of capital on common shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive income	Equity attributable to owners	Non-controlling interests	Shareholders' equity
Balance January 1, 2012	81,282	1	82,589	656,281	1,361	1,340	(277,083)	228	464,717	114,399	579,116
Common shares issued on July 26, 2012 by way of private placement	12,041	123,656							123,656		123,656
Issuance fees (Net of $2,338 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 (Note 26)			50,000						50,000		50,000
Issuance fees (Net of $526 of deferred income taxes)			(1,520)						(1,520)		(1,520)
Share options exercised (Note 26)	58	655			(148)				507		507
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)
Share-based payment					298				298		298
Dividends declared on Common shares							(50,693)		(50,693)		(50,693)
Dividends declared on Series A Preferred shares							(4,250)		(4,250)		(4,250)
Balance December 31, 2012	93,660	120,500	131,069	656,281	1,511	1,340	(330,621)	241	580,321	107,611	687,932

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

For the year ended December 31, 2011	Number of common shares (In 000's)	Common share capital account	Preferred shares	Contributed surplus from reduction of capital on common shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive income	Equity attributable to owners	Non-controlling interests	Shareholders' equity
Balance January 1, 2011	59,533	5,720	82,589	453,793	928	1,340	(188,296)	238	356,312	2,588	358,900
Common shares issued on											
April 4, 2011:											
– public offering	17,750	163,527							163,527		163,527
– private placement	3,999	39,018							39,018		39,018
– issuance fees (Net of $2,030 of deferred income taxes)		(5,776)							(5,776)		(5,776)
Business acquisition (Note 5 b))									—	114,968	114,968
Reduction of capital on Common shares (Note 26 e))		(202,488)		202,488					—		—
Net loss							(40,547)		(40,547)	(3,157)	(43,704)
Other items of comprehensive income								(10)	(10)		(10)
Total comprehensive loss	—	—	—	—	—	—	(40,547)	(10)	(40,557)	(3,157)	(43,714)
Share-based payment					433				433		433
Dividends declared on Common shares							(43,990)		(43,990)		(43,990)
Dividends declared on Series A Preferred shares							(4,250)		(4,250)		(4,250)
Balance December 31, 2011	81,282	1	82,589	656,281	1,361	1,340	(277,083)	228	464,717	114,399	579,116

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

For the years ended	Notes	December 31, 2012	December 31, 2011
Operating activities			
Net loss		(5,383)	(43,704)
Items not affecting cash:			
Depreciation		43,902	31,177
Amortization		21,835	19,793
Unrealized net (gain) loss on derivative financial instruments		(8,342)	61,479
Inflation compensation interest	8	3,362	7,199
Amortization of financing fees	8	729	231
Amortization of revaluation of long-term debt and convertible debentures	8	1,526	1,084
Accretion expense on asset retirement obligations	8	222	330
Accretion expense on contingent considerations	8	228	177
Share-based payment		298	433
Deferred income taxes		4,793	(13,828)
Others		353	100
Effect of exchange rate fluctuations		(84)	(296)
Interest on long-term debt and convertible debentures	8	57,214	44,101
Interest paid		(57,304)	(42,035)
(Gain) loss on contingent considerations	9	(357)	1,858
Contingent considerations paid	24	(983)	(1,147)
Provision for current income taxes		1,970	464
Net income taxes paid		(2,039)	(243)
		61,940	67,173
Changes in non-cash operating working capital items	28	241	(23,728)
		62,181	43,445
Financing activities			
Dividends paid on Common shares		(45,963)	(40,836)
Dividends paid on Preferred shares		(4,250)	(4,620)
Increase of long-term debt		405,657	270,117
Repayment of long-term debt		(202,245)	(47,475)
Payment of deferred financing costs		(4,248)	(5,983)
Net proceeds from issuance of Common shares		114,571	155,721
Net proceeds from issuance of Series C Preferred Shares		48,350	—
Proceeds from exercise of share options	26 d)	507	—
		312,379	326,924

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

For the years ended	Notes	December 31, 2012	December 31, 2011
Investing activities			
Cash acquired on business acquisition		—	4,943
Business acquisitions	5	(68,635)	(160,844)
Additions to property, plant and equipment		(186,760)	(178,896)
Additions to intangible assets		(1,929)	(3,469)
Additions to project development costs		(8,146)	(31,726)
Additions to other long-term assets		(27,892)	(724)
Increase of restricted cash and short-term investments		(34,396)	(15,531)
Reimbursement of a loan to a partner		—	1,000
Loans to partners		(23,444)	—
Proceeds from disposal of property, plant and equipment		56	28
Net funds withdrawn from the levelization reserve		—	494
Net funds (invested into) withdrawn from the hydrology/wind power reserve		(7,123)	5,933
Net funds withdrawn from the major maintenance reserve		514	1,562
		(357,755)	(377,230)
Effects of exchange rate changes on cash and cash equivalents		(36)	24
Net increase (decrease) in cash and cash equivalents		16,769	(6,837)
Cash and cash equivalents, beginning of year		35,279	42,116
Cash and cash equivalents, end of year		52,048	35,279
Cash and cash equivalents is comprised of:			
Cash		35,551	22,940
Short-term investments		16,497	12,339
		52,048	35,279

Additional information is presented in Note 28.

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

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. (the "Corporation") was incorporated under the *Canada Business Corporation Act* on October 25, 2002. The Corporation is a developer, owner and operator of renewable power-generating facilities, essentially focused on the hydroelectric, wind power and solar photovoltaic sectors. The head office of the Corporation is located at 1111, St-Charles Street West, East Tower, Suite 1255, Longueuil, Qc, J4K 5G4, Canada.

The consolidated financial statements were approved by the Board of Directors on March 14, 2013.

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

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

Principal subsidiaries

The following provides information about the principal subsidiaries of the Corporation as at December 31, 2012. All subsidiaries reside in Canada except the Horseshoe Bend Hydroelectric Company that resides in the USA.

Subsidiaries	Voting rights owned (1) %	Accounting method used
Ashlu Creek Investments, L.P.	100	Consolidation
Big Silver Creek Power L.P.	100	Consolidation
Brown Miller Power L.P. (2)	100	Consolidation
Glen Miller Power, L.P.	100	Consolidation
Horseshoe Bend Hydroelectric Company	100	Consolidation
Hydro-Windsor, L.P.	100	Consolidation
Innergex, L.P.	100	Consolidation
Innergex AAV, L.P. (3)	100	Consolidation
Innergex BDS, L.P. (3)	100	Consolidation
Innergex CAR, L.P. (3)	100	Consolidation
Innergex GM, L.P. (3)	100	Consolidation
Innergex MS, L.P. (3)	100	Consolidation
Innergex Montmagny, L.P.	100	Consolidation
Northwest Stave River Hydro L.P.	100	Consolidation
Rutherford Creek Power L.P.	100	Consolidation
Stardale Solar L.P. (4)	100	Consolidation
Trent-Severn Power, L.P.	100	Consolidation
Tretheway Creek Power L.P.	100	Consolidation
Boulder Creek Power L.P.	66.67	Consolidation with non-controlling interest
Creek Power Inc.	66.67	Consolidation with non-controlling interest
Fitzsimmons Creek Hydro, L.P.	66.67	Consolidation with non-controlling interest
Upper Lillooet River Power L.P.	66.67	Consolidation with non-controlling interest
Douglas Creek Project L.P. (5)	50.01	Consolidation with non-controlling interest
Fire Creek Project L.P. (5)	50.01	Consolidation with non-controlling interest
Lamont Creek Project L.P. (5)	50.01	Consolidation with non-controlling interest
Stokke Creek Project L.P. (5)	50.01	Consolidation with non-controlling interest
Tipella Creek Project L.P. (5)	50.01	Consolidation with non-controlling interest
Upper Stave Project L.P. (5)	50.01	Consolidation with non-controlling interest
Kwoiek Creek Resources, L.P.	50	Consolidation with non-controlling interest
Viger-Denonville, L.P.	50	Proportionate consolidation
Umbata Falls, L.P.	49	Proportionate consolidation

(1) % of ownership and % of voting rights held are the same except for Kwoiek Creek project where the Corporation owns more than 50% of the economic interest.
(2) Results are consolidated since the acquisition on October 12, 2012.
(3) Undivided owner of a 38% stake in the l'Anse-à-Valleau, Baie-des-Sables, Carleton, Gros-Morne and Montagne Sèche wind farms for which the proportionate consolidation accounting method is used.
(4) Results are consolidated since the acquisition on April 20, 2011.
(5) Results are consolidated since the acquisition on April 4, 2011.

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

These consolidated financial statements have been prepared in accordance 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 Amendments to IFRS affecting presentation and disclosure only

IAS 1 - Presentation of Items of Other comprehensive income

The International Accounting Standards Board ("IASB") issued amendments to IAS 1 Presentation of Financial Statements to split items of other comprehensive income between those that are reclassified to earnings and those that are not.

On June 16, 2011, the IASB issued amendments to IAS 1, Presentation of Financial Statements, which require entities to group together items within Other Comprehensive Income ("OCI") that may be reclassified to the profit or loss section of the income statement and to separately group together items that will not be reclassified to the profit or loss section of the income statement. The amendments also reaffirm existing requirements that profit or loss and OCI should be presented as either a single statement or two consecutive statements. The amendments are effective for financial years commencing on or after July 1, 2012.

In May 2012, the IASB issued further amendments to IAS 1, Presentation of Financial Statements which are effective for annual periods beginning on or after January 1, 2013 with early application permitted. IAS 1 requires an entity that changes accounting policies retrospectively, or makes a retrospective restatement or reclassification to present a statement of financial position as at the beginning of the preceding period. The amendments to IAS 1 clarify that an entity is required to present a third statement of financial position only when the retrospective application, restatement or reclassification has a material effect on the information in the third statement of financial position and that related notes are not required to accompany the third statement of financial position.

The Corporation has reviewed this standard and it will have no impact on its results of operations and financial position.

2.2 New and revised 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.

The standard will be effective for annual periods beginning on or after January 1, 2015, with earlier adoption permitted. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 10 - Consolidated Financial Statements

The IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation has reviewed this standard and it has no impact on its results of operations and financial position.

IFRS 11 - Joint arrangements

IFRS 11 deals with how a joint arrangement, of which two or more parties have joint control, should be classified. Under IFRS 11, joint arrangements are classified as joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangements. Joint ventures under IFRS 11 are required to be accounted for using the equity method of accounting whereas jointly controlled entities can be accounted for using the equity method of accounting or proportional consolidation.

Several investments in associates and joint ventures are consolidated in the Corporation under IFRS. These investments are either fully consolidated or proportionately consolidated. Under the IFRS 11 revised standard, some of these investments might have to be accounted for as investments on the consolidated statements of financial position with their results recognized as share of net earnings of a joint venture or an investee.

The effective date for the application of the revised standard is January 1, 2013. The Corporation has reviewed this standard and the application of IFRS 11 will result in changes in the accounting method of the joint ventures that will be accounted for using the equity method. Consequently the balances of each line item on the consolidated statements of financial position and the consolidated statements of earnings are expected to change significantly.

IFRS 12 - Disclosure of Interests in Other Entities

The IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires a company to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation has reviewed this standard and the impact will result in more extensive disclosures but will not have any impact on the amounts in the financial statements.

IFRS 13 - Fair Value Measurement

The IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation has reviewed this standard and it should not have any impact on its results of operations and financial position.

IAS 28 (2011) - Investments in Associates and Joint Ventures

IAS 28 was amended in 2011 to prescribe the accounting for investments in associates and sets out the application of the equity method when accounting for investments in associates and joint ventures. IAS 28 is effective for annual periods beginning on or after January 1, 2013. The Corporation has reviewed the impact of this amendment to IAS 28 and the impact will result in changes in accounting method for Umbata Falls, L.P. and Viger-Denonville, L.P. joint ventures that will have to be accounted for using the equity method.

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 to govern the financial and operating policies of the subsidiaries so as to obtain benefits from its activities. Subsidiaries are consolidated from the effective date of acquisition up to the effective date of disposal.

Joint ventures

A joint venture is a contractual agreement whereby the Corporation and other parties undertake an economic activity that is subject to joint control, arising when the strategic financial and operating policy decisions relating to the activities of the joint venture require the unanimous consent of the parties sharing control.

Joint venture arrangements that involve the establishment of a separate entity in which each venturer has an interest are referred to as jointly controlled entities.

The Corporation reports its interests in jointly controlled entities using proportionate consolidation. The Corporation's share of the assets, liabilities, income and expenses of jointly controlled entities is combined with the equivalent items in the consolidated financial statements on a line-by-line basis.

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.

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.

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.

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

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.

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 solar facility that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses.

Depreciation of hydroelectric power generating facilities is based on the estimated useful lives of the assets using the straight-line method over the lesser of (i) a period of 15 to 75 years or (ii) the period for which the Corporation owns the rights to the assets. Depreciation of wind farm facilities is based on the estimated useful lives of the assets using the straight-line method over the lesser of (i) a period of 15 to 25 years or (ii) the period for which the Corporation owns the rights to the assets. Depreciation of solar facility is based on the estimated useful lives of the assets using the straight-line method over the lesser of (i) a period of 25 years or (ii) the period for which the Corporation owns the rights to the assets. Other equipments are depreciated using the straight-line method over a period extending from 3 to 10 years. 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 2079	15 to 75 years
Wind farm facilities	2021 to 2037	15 to 25 years
Solar facility	2037	25 years

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

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 with finite useful lives are carried at cost less accumulated amortization and accumulated impairment losses.

Intangible assets consist of various permits, licenses and agreements. They are recorded at cost less accumulated amortization and accumulated impairment losses. Amortization starts when the related facility becomes ready for its intended use. They are amortized using the straight-line method over a period of 11 to 40 years ending on the maturity date of the permits, licenses or agreements of each facility. 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 three-year 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.

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	2014 to 2050	11 to 40 years
Wind farm facilities	2026 to 2028	19 to 20 years
Solar facility	2032	20 years
Extended warranties for wind turbines	2012 to 2016	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. 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 tangible and intangible assets other than goodwill

At the end of each reporting period, the Corporation reviews the carrying amounts of its tangible and intangible assets 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.

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

Others long-term assets include a $25,000 deposit for the acquisition of any of Hydromega'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 construction.

Provision 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 pre-tax 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.

All financial instruments are classified into one of the five categories: held-for-trading, loans and receivables, other financial liabilities, held-to-maturity investments or available-for-sale financial assets.

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 expenses in the consolidated statements of earnings.
- Net gains or losses on assets or liabilities classified as held for trading are included into gain (loss) 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 and loans to partners 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.
- Accounts payable and others payable, dividends payable to shareholders, construction holdbacks, accrual for acquisition of long-term assets, long-term debt, convertible debentures and contingent considerations 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 inflation provision and level 2 for interest rate swap, bond forward contracts and forward foreign exchange contracts.

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 Power Purchase Agreements ("PPA") 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 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 subsidy to Hydro-Québec. Gross EcoEnergy subsidies of $12,693 ($12,136 in 2011) are included in the operating 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. Amounts previously recognized in accumulated other comprehensive income are recognized in earnings when there is a reduction in the net investment.

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 and warrants, 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 and intangible assets, 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.

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

Property, plant and equipment represent a significant proportion of the Corporation's total assets. The Corporation reviews estimates of the useful lives of property, plant and equipment 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.

Property, plant and equipment and Intangible assets impairment

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.

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.

5. BUSINESS ACQUISITIONS

a) Acquisition of Brown Miller Power L.P.

On October 12, 2012, the Corporation finalized the acquisition of all the issued and outstanding units of Brown Miller Power L.P., the owner of the Brown Lake and Miller Creek run-of-river hydroelectric facilities located in British Columbia.The aggregate cash consideration subject to certain adjustments, is approximately $68,635.

All power generated from the facilities is sold to British Columbia Hydro and Power Authority under two PPAs with remaining terms that expires in 2016 for Brown Lake and in 2023 for Miller Creek.

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 Brown Miller Power L.P. facilities added an additional net installed capacity of approximately 40.2 MW to the Corporation's portfolio of operational hydroelectric facilities.

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

The following table reflects the preliminary purchase price allocation:

Accounts receivable	429
Prepaid and others	153
Property, plant and equipment	64,391
Intangible assets	13,436
Current liabilities	(9)
Deferred income taxes	(9,765)
Net assets acquired	68,635

The estimated purchase price and purchase price allocation remains subject to the completion of the valuation of the property, plant and equipment, intangible assets, deferred tax 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, 2012, the consolidated revenues and loss for the year ended December 31, 2012 would have been $184,606 and $6,123 respectively.

The amounts of revenues and net loss of Brown Miller Power L.P. since October 12, 2012 included in the consolidated statement of earnings are $1,013 and $137 respectively for the 81 days ended December 31, 2012.

b) Acquisition of Cloudworks Energy Inc.

On April 4, 2011, the Corporation finalized the acquisition of all the issued and outstanding shares of Cloudworks Energy Inc. (“Cloudworks”) (the “Cloudworks Acquisition”). The aggregate consideration was $191,083, $149,669 of which was payable in cash (the “Cash Consideration”), $39,018 of which was payable by the issuance, by way of a private placement, of common shares of the Corporation at a price of $9.75 per common share, and $2,396 which is payable by way of contingent considerations based on the performance of the Cloudworks portfolio of assets.

Cloudworks' portfolio of assets consists of a 50.01% interest in six run-of-river hydroelectric facilities (the “Harrison Operating Facilities”) with a combined gross installed capacity of 150 megawatts; full ownership of 81 MW of run-of-river hydroelectric projects under development with 40-year PPAs; and full ownership of run-of-river hydroelectric projects in various stages of development with a potential aggregate installed capacity in excess of 800 MW.

All power generated from the operating facilities is sold to British Columbia Hydro and Power Authority under 40-year PPAs.

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. By adding the recently commissioned low-risk hydroelectric facilities to its portfolio of assets, the Corporation believes it is improving the stability of its cash flows and the sustainability of its dividend. Also, the transaction is expected to be accretive to the Corporation's upon commissioning of three run-of-river hydroelectric projects under development with 40-year PPAs with a potential installed capacity of 81 MW. Furthermore, through the transaction, the Corporation significantly expanded its footprint in British Columbia.

To finance the Cash Consideration, the Corporation sold subscription receipts of the Corporation through a syndicate of underwriters on a bought-deal basis. The agreement with the syndicate included the issuance of 17,750,000 subscription receipts at a price of $9.35 per subscription receipt to raise gross proceeds of $165,963. The proceeds of the subscription receipt financing were held in escrow pending the completion of the Cloudworks Acquisition. The subscription receipts have therefore been exchanged on a one-for-one basis for common shares of the Corporation upon the closing of the Cloudworks' acquisition for no additional consideration.

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

i. The net proceeds from the subscriptions receipts along with the private placement was determined as follows:

	Subscriptions receipts	Private placement	Total
Shares issued (in 000's)	17,750	3,999	21,749
Price of shares ($ per share)	9.35	9.75	9.42
Value of shares that have been issued	165,963	39,018	204,981
Issuance fees	(7,806)		(7,806)
Dividend equivalent payment refunded to subscriptions holders	(2,436)		(2,436)
Net proceeds	155,721	39,018	194,739

From the net proceeds of $194,739 a total of $188,687 was used for the acquisition of Cloudworks. The balance was used by the Corporation to enhance its financial flexibility, to reduce indebtness and for general corporate purposes.

ii. The total purchase price has been calculated as follows:

Purchase price to vendors	188,687
Contingent considerations	2,396
Total purchase price	191,083

iii. The following table reflects the final purchase price allocation:

	Final purchase price allocation
Cash and cash equivalents	4,942
Restricted cash and short-term investments	37,693
Accounts receivable	3,080
Prepaid and others	211
Reserve accounts	28,601
Property, plant and equipment	438,541
Intangible assets	235,974
Project development costs	100,746
Deferred tax assets	1,654
Other long-term assets	2,936
Accounts payable and other payables	(14,471)
Current portion of long-term debt	(6,963)
Long-term debt	(459,273)
Deferred tax liabilities	(67,620)
Non-controlling interests	(114,968)
Net assets acquired	191,083

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

iv. The share purchase agreement provides for the potential contingent considerations of additional amounts to the vendors over a period of more than 40 years. The fair market value of the contingent considerations to be paid was estimated at $2,396. See Note 24 for more details.

v. If the acquisition had taken place on January 1, 2011, the consolidated revenues and loss for the year ended December 31, 2011 would have been $154,650 and $50,675, respectively.

The amounts of revenue and net loss of Cloudworks Energy Inc. since April 4, 2011 included in the consolidated statement of earnings were $46,595 and $141, respectively, for the 271 days ended December 31, 2011.

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

c) Acquisition of Stardale Solar Project

On April 20, 2011, the Corporation finalized the acquisition of all the issued and outstanding shares of Solaris Energy Partners Inc. (“Solaris”). The aggregate consideration was $11,778 of which $11,175 was payable in cash and $603 was payable by way of contingent considerations. Solaris owned the rights to develop the 33.2 MW_{DC} Stardale Photovoltaic Solar Project (the “Stardale Project”), located in Ontario, Canada.

All energy generated by the Stardale Project is sold to Ontario Power Authority under 20-year PPAs.

With the acquisition of the Stardale Project, the Corporation positioned itself in a new sector. The solar technology is proven, reliable and simple and the Corporation believes that the operational risks are minimal. In addition, the sun provides for a very stable and predictable resource which for the Corporation believes will result in the Stardale Project generating a stable stream of cash flows for the next 20 years and beyond.

The total purchase price has been calculated as follows:

Purchase price to vendors	11,175
Contingent considerations	603
Total purchase price	11,778

The following table reflects the final purchase price allocation:

	Final purchase price allocation
Cash and cash equivalents	1
Accounts receivable	59
Property plant and equipment	3,722
Intangible assets	9,538
Other long-term assets	600
Deferred tax liabilities	(2,142)
	11,778

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

The share purchase agreement provides for the potential contingent considerations of additional amounts to the vendors over a period of three years. The fair market value of the contingent considerations to be paid was estimated at $603. See Note 24 for more details.

If the acquisition had taken place on January 1, 2011, the consolidated revenues and net loss for the year ended December 31, 2011 would have been similar as the project was under construction and costs were capitalized.

The amounts of revenues and earnings of Stardale Solar Project since April 20, 2011 included in the consolidated statement of earnings were $nil for the 255 days ended December 31, 2011.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Corporation records embedded derivatives separately from the host contracts. 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, 2012 over the remaining terms of these agreements, discounted at a rate of 3.06%. The expected impact of a 0.1% increase in the long-term inflation rate would reduce the fair value of these financial instruments by $822; a 0.1% drop in the long-term inflation rate would increase fair value of these financial instruments by $818.

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

The Corporation holds forward 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 $5,447. Conversely, a decrease in swap rates curve of 0.1% would result in an decrease of $5,523 of the fair value of these financial instruments.

The Corporation holds forward foreign exchange contracts that enable it to eliminate the risk of any Euro appreciation versus the Canadian dollar on equipment purchases. The forward foreign exchange contracts will mature in 2013. The estimated impact of an increase of the Canadian dollar by $0.01 against €1.00 would decrease the fair value of these financial instruments by $67. Conversely, a decrease of the Canadian dollar by $0.01 against €1.00 would result in an increase of $67 of the fair value of these financial instruments.

For the year ended December 31, 2012

Reconciliation of fair value measurements of financial assets

	Forward foreign exchange contracts (Level 2)	Interest hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2012	—	—	10,039	10,039
Variation in fair value of derivative financial instruments	423	—	(1,648)	(1,225)
Settlements	—	—	—	—
Unrealized net gain (loss) on derivative financial instruments	423	—	(1,648)	(1,225)
As at December 31, 2012	423	—	8,391	8,814

Reconciliation of fair value measurements of financial liabilities

	Forward foreign exchange contracts (Level 2)	Interest hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2012	—	91,445	—	91,445
Variation in fair value of derivative financial instruments	—	4,560	—	4,560
Settlements	—	(14,127)	—	(14,127)
Unrealized net gain on derivative financial instruments	—	(9,567)	—	(9,567)
As at December 31, 2012	—	81,878	—	81,878

The classification of the fair value hierarchy of all the financial assets and liabilities remained the same during 2012.

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

For the year ended December 31, 2011

Reconciliation of fair value measurements of financial assets

	Interest hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2011	322	10,891	11,213
Variation in fair value of derivative financial instruments	(322)	(852)	(1,174)
Settlements	—	—	—
Unrealized net loss on derivative financial instruments	(322)	(852)	(1,174)
As at December 31, 2011	—	10,039	10,039

Reconciliation of fair value measurements of financial liabilities

	Interest hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2011	31,140	—	31,140
Variation in fair value of derivative financial instruments	60,305	—	60,305
Settlements	—	—	—
Unrealized net loss on derivative financial instruments	60,305	—	60,305
As at December 31, 2011	91,445	—	91,445

Reported in the financial statements.

As at	December 31, 2012	December 31, 2011
Current assets – derivative financial instruments	2,116	1,791
Long-term assets – derivative financial instruments	6,698	8,248
Current liability – derivative financial instruments	(17,855)	(20,287)
Long-term liability – derivative financial instruments	(64,023)	(71,158)
	(73,064)	(81,406)

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

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, 2012	December 31, 2011
Bond forwards, from 2.00% to 2.88%	2013	None	52,500	137,500
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 swap, 4.41%	2018	2013	30,000	30,000
Interest rate swap, 4.27%	2018	2013	52,600	52,600
Interest rate swap, from 4.83% to 4.93%, amortizing	2026	None	43,514	45,705
Interest rate swap, from 3.35% to 3.45%, amortizing	2027	2013	42,792	45,605
Interest rate swaps, from 3.74% to 3.85%, amortizing	2030	None	101,780	101,996
Interest rate swap, 4.22%, amortizing	2030	2016	30,021	31,690
Interest rate swap, 4.25%, amortizing	2031	2016	47,323	49,940
Interest rate swap, from 3.98% to 4.11%, amortizing	2034	None	23,392	23,885
Interest rate swaps, from 4.61% to 4.70%, amortizing	2035	2025	105,031	107,111
Interest rate swap, 2.85%, amortizing	2041	2016	19,853	20,100
			566,806	664,132

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.

The terms of the contract reducing the Corporation's foreign exchange risk is the following:

			Notional amounts	
Contract	Maturity	Early termination option	December 31, 2012	December 31, 2011
Euros forwards, exchange rate of 1.25$ CDN for €1	2013	None	6,781	—
			6,781	—

7. OPERATING EXPENSES

	December 31, 2012	December 31, 2011
Salaries	2,742	2,450
Insurance	1,812	1,423
Operation and maintenance	13,370	12,161
Property taxes and royalties	11,209	8,192
	29,133	24,226

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

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

8. FINANCE COSTS

	December 31, 2012	December 31, 2011
Interest on long-term debt and on convertible debentures	57,214	44,101
Inflation compensation interest	3,362	7,199
Amortization of financing fees	729	231
Amortization of revaluation of long-term debt and of convertible debentures	1,526	1,084
Accretion expense on asset retirement obligations	222	330
Accretion expense on contingent considerations	228	177
	63,281	53,122

9. OTHER NET EXPENSES (REVENUES)

	December 31, 2012	December 31, 2011
Transaction costs	2,766	1,863
Realized loss on derivative financial instruments	14,127	—
Realized gain on foreign exchange	(111)	—
(Gain) loss on contingent considerations	(357)	1,858
Other net revenues	(1,128)	(1,028)
Loan impairment	1,000	—
Compensation from contractor	(770)	—
	15,527	2,693

10. 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.

	December 31, 2012	December 31, 2011
Salaries and short-term benefits	3,936	4,437
Attendance fees for members of the Board of Directors	578	526
Termination benefits	227	390
Long-term performance share plan	767	—
Share-based payment	298	433
	5,806	5,786

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

11. 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:

	December 31, 2012	December 31, 2011
Operating expenses	2,742	2,450
General and administrative	4,058	4,621
Prospective projects expenses	2,147	1,933
Transaction costs	1,059	929
Charged to partners	1,030	493
Capitalized in property, plant and equipment	3,737	1,950
Capitalized in project development costs	1,693	1,950
	16,466	14,326

12. INCOME TAXES

a) Income tax recognized in profit or loss

	December 31, 2012	December 31, 2011
Current tax		
Current tax expense in respect of the current year	2,039	464
Adjustments recognized in the current year in relation to the current tax (recovery) expense of prior years	(69)	—
	1,970	464
Deferred tax		
Deferred tax expense (recovery) recognized in the current year	121	(13,510)
Reduction in deferred income tax rates	—	(433)
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	560	115
	4,793	(13,828)
Total income tax expense (recovery) recognized in the current year to continuing operations	6,763	(13,364)

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

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

	December 31, 2012	December 31, 2011
Earnings (loss) before income taxes	1,380	(57,068)
Canadian statutory income tax rate	26.0%	27.5%
Provision for income taxes (recovery) calculated at the statutory rate	359	(15,694)
Items affecting the statutory rate:		
Income that is exempt from taxation	—	(187)
Non-deductible expenses	780	1,642
Recognition of tax losses	(227)	(325)
Effect of previously unrecognized and unused tax losses and deductible temporary differences now recognized as deferred tax assets	—	(572)
Income taxable at a higher rate than the Canadian statutory rate	134	482
Reduction in deferred income tax rates	—	(433)
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	577	696
Income tax on dividends on preferred shares	94	260
Adjustments recognized in the current year in relation to the current tax of prior years	(69)	—
Adjustments recognized in the current year in relation to the deferred tax of prior years	560	115
Income tax expense on profit or loss allocated to minority interests on non-taxable entities	408	461
Others	35	191
Provision for income taxes (recovery) recognized in profit or loss relating to continuing operations	6,763	(13,364)

The tax rate used for 2012 and 2011 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 Federal tax rate applicable in 2012 decreased from 16.5% to 15%.

b) Income tax recognized directly in equity

	December 31, 2012	December 31, 2011
Deferred tax		
Arising on transactions with owners:		
Share issue expenses deductible over five years	(2,864)	(2,030)
Total income tax recognized directly in equity	(2,864)	(2,030)

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

c) Income tax recognized in other comprehensive income

	December 31, 2012	December 31, 2011
Deferred tax		
Arising on income and expenses recognized in other comprehensive income:		
Foreign exchange on translation of a self-sustaining foreign subsidiary	(12)	15
Foreign exchange on the designated portion of the US dollar denominated debt used as hedge on the investment in a self-sustaining foreign subsidiary	13	(15)
Total income tax provision recognized directly in other comprehensive income	1	—

d) Current tax assets and liabilities

	December 31, 2012	December 31, 2011
Current tax assets		
Benefit of tax losses to be carried back to recover taxes paid in prior periods	440	1,650
Tax refund receivable	3	14
	443	1,664
Current tax liabilities		
Income tax payable	1,541	2,835

e) Deferred tax balances

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

	December 31, 2012	December 31, 2011
Deferred tax assets	5,846	24,485
Deferred tax liabilities	(139,265)	(140,454)
	(133,419)	(115,969)

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

	As at January 1, 2012	Recognized in statement of earnings	Net exchange differences	Recognized in other items of comprehensive income	Recognized directly in shareholders' equity	Acquisitions	As at December 31, 2012
Deferred tax assets (liabilities) in relation to:							
Investment into subsidiaries and in entities subject to significant influence	(2,910)	2,478	—	12	—	—	(420)
Property, plant and equipment	(62,441)	2,399	(28)	—	—	(7,275)	(67,345)
Project development costs	(8,589)	(15,940)	—	—	—	—	(24,529)
Intangible assets	(75,290)	1,738	15	—	—	(8,201)	(81,738)
Derivative financial instruments	24,875	1,521	—	—	—	—	26,396
Convertible debentures	(262)	45	—	—	—	—	(217)
Financing fees	4,109	(3,888)	—	—	2,864	—	3,085
Long-term debt	(8,425)	(129)	—	—	—	—	(8,554)
Income tax on dividends on Preferred shares	—	350	—	—	—	—	350
Non-repatriated income from foreign subsidiaries	(399)	(114)	—	—	—	—	(513)
	(129,332)	(11,540)	(13)	12	2,864	(15,476)	(153,485)
Tax losses and minimum taxes	13,363	6,747	(31)	(13)	—	—	20,066
	(115,969)	(4,793)	(44)	(1)	2,864	(15,476)	(133,419)

As at December 31, 2012, the Corporation, its subsidiaries and joint ventures have non-capital losses totaling approximately $79,000 that may be applied against future taxable income. These non-capital losses expire gradually between 2027 and 2032. The Corporation and its subsidiaries recorded capital losses totaling approximately $1,000 that may be applied against capital gains in future years.

The Corporation recognized a deferred tax asset on non-capital and capital losses because it is probable that taxable profit and taxable capital gains 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, 2011	Recognized in statement of earnings	Net exchange differences	Recognized in other items of comprehensive income	Recognized directly in shareholders' equity	Acquisitions	As at December 31, 2011
Deferred tax assets (liabilities) in relation to:							
Investment into subsidiaries and in entities subject to significant influence	(352)	(666)	—	(15)	—	(1,877)	(2,910)
Property, plant and equipment	(43,788)	(16,983)	26	—	—	(1,696)	(62,441)
Project development costs	3,486	10,255	—	—	—	(22,330)	(8,589)
Intangible assets	(49,925)	9,348	(9)	—	—	(34,704)	(75,290)
Derivative financial instruments	9,559	15,316	—	—	—	—	24,875
Convertible debentures	(303)	41	—	—	—	—	(262)
Financing fees	3,109	(2,454)	(1)	—	2,030	1,425	4,109
Long-term debt	(388)	226	—	—	—	(8,263)	(8,425)
Income tax on dividends on Preferred shares	435	(435)	—	—	—	—	—
Non-repatriated income from foreign subsidiaries	(363)	(36)	—	—	—	—	(399)
	(78,530)	14,612	16	(15)	2,030	(67,445)	(129,332)
Tax losses and minimum taxes	9,067	(784)	18	15	—	5,047	13,363
	(69,463)	13,828	34	—	2,030	(62,398)	(115,969)

(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, 2012	December 31, 2011
Tax losses - revenue in nature	4,284	3,747
Tax losses - capital in nature	569	569
Transaction costs	3,095	2,032
	7,948	6,348

The unrecognized tax losses will expire gradually between 2023 and 2032.

13. COMPUTATION OF EARNINGS AVAILABLE TO COMMON SHAREHOLDERS

The net earnings (loss) of the Corporation is adjusted for the preferential dividend on the Preferred shares as follows:

	December 31, 2012	December 31, 2011
Net earnings (loss) attributable to owners of the parent	1,405	(40,547)
Dividends declared on Series A Preferred Shares	(4,250)	(4,250)
Net loss available to common shareholders	(2,845)	(44,797)
Weighted average number of common shares (in 000)	86,557	75,681
Basic net loss per share ($)	(0.03)	(0.59)
Weighted average number of common shares (in 000)	86,557	75,681
Effect of dilutive elements on common shares (in 000) (a)	151	74
Diluted weighted average number of common shares (in 000)	86,708	75,755
Diluted net loss per share ($) (b)	(0.03)	(0.59)

a. During the year, 1,263,000 stock options (1,869,420 as at December 31, 2011) and 7,558,684 shares which can be issued on conversion of convertible debentures (same as at December 31, 2011) were excluded in the calculation of diluted weighted average number of shares outstanding as the exercise price was above the average market price of common shares during the year.

b. During the year, 1,473,684 stock options (808,024 as at December 31, 2011) 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.

14. RESTRICTED CASH AND SHORT-TERM INVESTMENTS

	December 31, 2012	December 31, 2011
Restricted chequing accounts	7,676	22,820
Proceeds accounts	73,539	24,056
Debt service payment accounts	6,596	6,539
	87,811	53,415

As part of the Kwoiek Creek LP credit agreement, the Corporation maintains restricted chequing accounts and a restricted proceeds account. The balance of the loan proceeds is held in restricted accounts managed by Kwoiek Creek lender and amounts are transferred from time to time into the restricted chequing accounts to finance the construction of the Kwoiek Creek Project. The restricted chequing accounts are used to pay the current construction costs of the Kwoiek Creek Project and to hold the construction holdbacks amounts that will be released at the end of the construction of the project.

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

In relation with the Harrison Operating Facilities, the Corporation maintains some restricted cash accounts.

In accordance with the terms of a trust indenture, the balance of the loan proceeds was held in restricted proceeds accounts managed by the Bank of New York as trustee and was released once the covenants under the trust indenture were met during year 2012.

The debt service payment accounts require a monthly transfer equal to one-sixth of the next semi-annual bond payments required on the outstanding senior bonds issued by Harrison Hydro Finance Inc. ("HHFI") and a monthly transfer equal to one-third of the next quarterly bond payment required on the outstanding junior bonds issued by HHFI. These amounts mirror the loan payments required by the Senior LP Credit Agreement and the Junior LP Credit Agreement to HHFI with the addition of an interest spread charged by HHFI. Senior and junior loan payments are taken from this account on their due dates.

15. ACCOUNTS RECEIVABLE

	December 31, 2012	December 31, 2011
Trade	19,145	15,643
Commodity taxes	10,307	14,445
Investment tax credits	1,487	1,497
Payment receivable for property, plant and equipment	15,257	4,130
Others	4,590	1,179
	50,786	36,894

Substantially all of the Corporation's trade receivables relate to electricity sold to public utilities including Hydro-Quebec, British Columbia Hydro, Ontario Electricity Financial Corporation, Ontario Power Authority, Hydro One Inc. 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 Ontario Electricity Financial Corporation and Ontario Power Authority obligations under the PPAs to which it is a party. Hydro One Inc. currently holds a credit rating of A+ from S&P. Idaho Power Company currently has a credit rating of BBB from S&P.

The payment receivable for property, plant and equipment is also receivable from Hydro-Québec and is related to the Gros Morne wind farm. Commodity taxes and investment tax credits are receivable from the federal or provincial governments, following the development and construction of projects.

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.

16. RESERVE ACCOUNTS

During the year, the amounts held in the hydrology/wind power reserve generated investment income of $283 ($398 in 2011) .

During the year, the amounts held in the major maintenance reserve generated investment income of $23 ($38 in 2011).

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

The table below summarizes the changes in the reserve accounts:

			December 31, 2012
	Hydrology / wind power reserve	Major maintenance reserve	Total
Reserves – As at January 1, 2012	39,045	3,109	42,154
Investments in the reserves	10,287	997	11,284
Withdrawals	(3,164)	(1,511)	(4,675)
Impact of foreign exchange fluctuations	(14)	—	(14)
Reserves – As at December 31, 2012	46,154	2,595	48,749
Less:			
Current portion	(1,816)	—	(1,816)
Reserves – As at December 31, 2012	44,338	2,595	46,933

				December 31, 2011
	Hydrology / wind power reserve	Major maintenance	Levelization reserve	Total
Reserves – As at January 1, 2011	16,511	4,436	494	21,441
Reserves acquired on business acquisition (Note 5)	28,376	225	—	28,601
Investments in the reserves	2,481	810	—	3,291
Withdrawals	(8,414)	(2,372)	(494)	(11,280)
Impact of foreign exchange fluctuations	91	10	—	101
Reserves – As at December 31, 2011	39,045	3,109	—	42,154

The Corporation used a portion of the cash held in the reserve accounts to purchase investments aimed at generating additional revenues to provide more stability. As at December 31, 2012, the carrying values and market values of these investments were as follows:

Reserve account investments	Maturity	Market value	Net carrying value
Government-backed securities	2013	621	621
Short-term investments	2013	11,280	11,280
Cash and cash equivalents	-	36,848	36,848
		48,749	48,749

The market value of the securities backed by the US government 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 $42,542 in the reserve accounts is restricted by credit agreements.

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

17. PROPERTY, PLANT AND EQUIPMENT

	Land	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2012	1,887	886,163	303,101	—	161,239	4,650	1,357,040
Additions	—	612	3,682	153	167,678	1,771	173,896
Business acquisition	220	64,112	—	—	—	59	64,391
Transfer of assets upon commissioning			64,036	123,980	(188,016)		—
Dispositions	—	(63)	—	—	—	(277)	(340)
Net foreign exchange differences	(2)	(115)	—	—	—	(3)	(120)
As at December 31, 2012	2,105	950,709	370,819	124,133	140,901	6,200	1,594,867
Accumulated depreciation							
As at January 1, 2012	—	(63,803)	(31,918)	—	—	(1,485)	(97,206)
Depreciation	—	(23,378)	(15,337)	(3,965)	—	(1,222)	(43,902)
Dispositions	—	8	—	—	—	149	157
Net foreign exchange differences	—	28	—	—	—	—	28
As at December 31, 2012	—	(87,145)	(47,255)	(3,965)	—	(2,558)	(140,923)
Net value as at December 31, 2012	2,105	863,564	323,564	120,168	140,901	3,642	1,453,944

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

Property, plant and equipment includes capitalized financing costs of $11,440 as at December 31, 2012 ($2,795 at December 31, 2011) incurred prior to their intended use or sale.

The financing costs related to a specific project financing are entirely capitalized to the specific property, plant and equipment. Financing costs related to corporate financing are capitalized for the portion of the financing actually used for a specific property, plant and equipment.

The cost of the wind farm facilities under construction were reduced by investment tax credits of $472 ($352 as at December 31, 2011).

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

	Land	Hydroelectric facilities	Wind farm facilities	Facilities under construction	Other equipments	Total
Cost						
As at January 1, 2011	70	447,778	197,456	31,148	1,917	678,369
Additions	—	1,305	484	190,999	1,397	194,185
Business acquisitions	1,815	437,185	—	1,907	1,356	442,263
Transfer of assets upon commissioning	—	—	105,161	(105,161)	—	—
Transfer from projects under development	—	—	—	42,346	—	42,346
Dispositions	—	(224)	—	—	(20)	(244)
Net foreign exchange differences	2	119	—	—	—	121
As at December 31, 2011	1,887	886,163	303,101	161,239	4,650	1,357,040
Accumulated depreciation						
As at January 1, 2011	—	(43,600)	(21,838)	—	(621)	(66,059)
Depreciation	—	(20,226)	(10,080)	—	(871)	(31,177)
Dispositions	—	53	—	—	7	60
Net foreign exchange differences	—	(30)	—	—	—	(30)
As at December 31, 2011	—	(63,803)	(31,918)	—	(1,485)	(97,206)
Net value as at December 31, 2011	1,887	822,360	271,183	161,239	3,165	1,259,834

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

18. INTANGIBLE ASSETS

The Corporation's intangible assets are related to the following assets:

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
Cost					
As at January 1, 2012	419,834	80,144	—	16,538	516,516
Additions	6,038	1,438	—	191	7,667
Business acquisitions	13,436	—	—	—	13,436
Transfer of assets upon commissioning	—	—	9,538	(9,538)	—
Net exchange differences	(44)	—	—	—	(44)
As at December 31, 2012	439,264	81,582	9,538	7,191	537,575
Accumulated amortization					
As at January 1, 2012	(60,174)	(15,080)	—	—	(75,254)
Amortization	(16,614)	(4,923)	(298)	—	(21,835)
Net exchange differences	12	—	—	—	12
As at December 31, 2012	(76,776)	(20,003)	(298)	—	(97,077)
Net value as at December 31, 2012	362,488	61,579	9,240	7,191	440,498

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
Cost					
As at January 1, 2011	189,191	77,094	—	—	266,285
Additions	415	3,050	—	—	3,465
Business acquisitions	230,184	—	—	9,538	239,722
Transfer from projects under development	—	—	—	7,000	7,000
Net exchange differences	44	—	—	—	44
As at December 31, 2011	419,834	80,144	—	16,538	516,516
Accumulated amortization					
As at January 1, 2011	(45,979)	(9,468)	—	—	(55,447)
Amortization	(14,181)	(5,612)	—	—	(19,793)
Net exchange differences	(14)	—	—	—	(14)
As at December 31, 2011	(60,174)	(15,080)	—	—	(75,254)
Net value as at December 31, 2011	359,660	65,064	—	16,538	441,262

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

19. PROJECT DEVELOPMENT COSTS

	December 31, 2012	December 31, 2011
Cost		
Beginning of year	98,042	5,908
Additions	9,123	40,734
Business acquisition	—	100,746
Transfer to property, plant and equipment	—	(42,346)
Transfer to intangible assets	—	(7,000)
End of year	107,165	98,042

Project development costs include capitalized interest of $651 ($347 in 2011).

20. GOODWILL

Allocation of goodwill to each cash-generating unit is as follows:

	December 31, 2012	December 31, 2011
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, 2012 and 2011, the Corporation conducted an annual goodwill impairment test. 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 discount rate of 6.44% 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 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.

21. ACCOUNTS PAYABLE AND OTHER PAYABLES

	December 31, 2012	December 31, 2011
Trade and other payables	24,298	18,334
Current portion of construction holdbacks	7,642	373
Capital tax	—	351
Interest payable	6,431	6,517
Commodity taxes	2,966	1,041
	41,337	26,616

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

22. LONG-TERM DEBT

	December 31, 2012	December 31, 2011
Revolving credit term facility (a)		
Prime rate advances renewable until August 2016 (rate of 3.85%, 3.60% in 2011)	20	20
Bankers' acceptances renewable until August 2016 (average weighted rate of 3.04%, 2.84% in 2011)	189,780	164,780
LIBOR advances, US$13,900 renewable until August 2016 (rate of 2.10%, same in 2011)	13,829	14,136
Term loans		
Glen Miller, floating rate term loan repaid in 2012 (rate of 2.66% in 2011) (b)	—	13,500
Carleton, floating rate term loan maturing in 2013 (rate of 2.72%, 2.57% in 2011) (c)	43,412	46,298
Umbata Falls, floating rate term loan maturing in 2014 (rate of 2.54%, 2.42% in 2011) (d)	23,392	23,885
Fitzsimmons Creek, floating rate term loan maturing in 2016 (rate of 2.37%, 2.52% in 2011) (e)	22,133	22,458
Hydro-Windsor, 8.25% fixed rate term loan maturing in 2016 (f)	4,145	5,027
Montagne-Sèche, floating rate term loan maturing in 2016 (rate of 3.73%, 3.47% in 2011) (g)	30,021	26,200
Rutherford Creek, 6.88% fixed rate term loan maturing in 2024 (h)	48,634	50,000
Ashlu Creek, floating rate term loan maturing in 2025 (rate of 2.66%, 2.63% in 2011) (i)	100,810	102,669
L'Anse-à-Valleau, floating rate term loan maturing in 2026 (rate of 2.33%, 2.30% in 2011) (j)	43,515	45,706
Stardale, floating rate term loan maturing in 2030 (rate of 3.48%, 3.45% in 2011) (k)	110,630	73,706
Kwoiek Creek, 20% fixed rate term loan during development phase and 14% fixed rate during construction and operation phases (l)	150	150
Kwoiek Creek, 5.08% fixed rate construction loan (l)	168,500	—
Other loans with various maturities and interest rates (m)	222	73
Bonds		
Harrison Operating Facilities, Senior Real Return bond maturing in 2049 (rate of 5.20%, 6.94% in 2011) (n) (q)	225,137	226,338
Harrison Operating Facilities, 6.66% Senior Fixed Rate bond maturing in 2049 (o) (q)	213,738	215,570
Harrison Operating Facilities, Junior Real Return bond maturing in 2049 (rate of 6.20%, 7.94% in 2011) (p) (q)	26,760	26,484
	1,264,828	1,057,000
Deferred financing costs	(10,727)	(7,488)
	1,254,101	1,049,512
Current portion of long-term debt (net of $33 deferred financing costs, nil in 2011)	(64,452)	(19,475)
Long-term portion	1,189,649	1,030,037

(a) Revolving credit term facility

On July 17, 2012, the Corporation exercised a portion of the accordion feature on its revolving term credit facility, increasing its borrowing capacity from $350,000 to $425,000.

All terms and conditions, including the August 2016 maturity, remain unchanged.

As at December 31, 2012, a LIBOR rate advance of $13,829 (US$13,900) along with Bankers' Acceptances ("BA") rate advances and prime rate advances totaling $189,800 were due under this facility. An amount of $21,123 has been used to secure letters of credit. Thus, the unused and available position of the facility was $200,248. The carrying value of assets of the Corporation and subsidiaries given as securities under this facility totals approximately $747,000.

(b) Glen Miller

During the first quarter of 2012, the Corporation repaid entirely the term loan in an amount of $13,500.

(c) Carleton

The loan consists of a five-year term loan, amortized over a 18.5-year period which started on December 31, 2008. The loan bears interest at BA rate plus an applicable margin. The term loan is repayable in quarterly instalments. The principal repayments are variable and are set at $2,985 for 2013.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $833. As at December 31, 2012, an amount of $499 has been used to secure one letter of credit. This debt is secured by all Innergex CAR, LP's assets with a carrying value of approximately $91,000. It is expected that the loan will be refinanced in the course of 2013.

(d) Umbata Falls

The loan consists of a five-year term loan, amortized over a 25-year period starting in September 2009. The term loan bears interest at BA rate plus an applicable margin. The term loan is repayable in quarterly instalments. The principal repayments are variable and are set to $1,073 for 2013 (the share of the Corporation is 49%).

The lender also agreed to make available a letter of credit facility in a principal amount not exceeding $500. As at December 31, 2012, 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 $82,500 (the share of the Corporation is 49%).

(e) 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 $262 for 2013.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $150. As at December 31, 2012, 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 $26,600.

(f) 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 2013 will amount to $854. The loan is secured by Hydro-Windsor LP's assets, with a carrying value of approximately $11,500.

(g) Montagne-Sèche

The loan consists of a five-year term loan, amortized over an 18-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 $1,218 for 2013.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $445. As at December 31, 2012, 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 $46,600.

(h) 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 2013 are set to $2,877. The loan is secured by Rutherford Creek Power Limited Partnership's assets, with a carrying value of approximately $88,400.

(i) 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 $2,213 for 2013.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $3,000. As at December 31, 2012 an amount of $1,656 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 $179,400.

(j) 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 $2,327 for 2013.

The lenders also agreed to make available a credit facility of $1,200 in order to secure letters of credit . As at December 31, 2012, 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 $71,600.

(k) 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 repayble in quarterly installments.The principal repayments are variable and set to $4,410 for 2013. 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, 2012, 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 $136,300.

(l) Kwoiek Creek

The Kwoiek Creek Resources Limited Partnership's long-term debt consists of a loan made by the partner of the Corporation in the Kwoiek Creek Project. As per the agreements related to the project, both partners can participate in the financing of the project. The loan bears interests at a rate of 20% during the development phase and 14% during the construction and operating phases. The partner loan made to Kwoiek Creek Resources Limited Partnership amounts to $150. The Corporation's loan made to Kwoiek Creek Resources Limited Partnership, which was eliminated in the financial statement consolidation process, amounted to $44,800 as at December 31, 2012.

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 5.075%; 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 $187,800.

(m) Other loans

The other loans represent loans with various maturities and interest rates.

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

(n) 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 are $5,790 before CPI adjustment. On December 1, 2031, the payment amount decreases to $4,481 before CPI adjustment where it remains until maturity. For 2013, the principal repayments are set to $5,051. The bond is secured by the Harrison Operating Facilities.

(o) Harrison Operating Facilities, Senior Fixed Rate bond

The Harrison Operating Facilities Senior Fixed Rate bond bears interest at 6.66%. Payments on this bond are due semi-annually with the bond maturing on September 1, 2049. Semi-annual payments amount to $8,072. On September 1, 2030 the payment amount decreases to $6,724 where it remains until maturity. For 2013, the principal repayments are set to $2,780. The bond is secured by the Harrison Operating Facilities.

(p) 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 amount to $291 before CPI adjustment. 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.

(q) 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 $697,100.

	Senior Real Return Bond	Senior Fixed Rate Bond	Junior Real Return Bond	Total
Balance – December 31, 2011	226,338	215,570	26,484	468,392
Inflation compensation interest	3,019	—	343	3,362
Principal repayment	(4,899)	(2,632)	—	(7,531)
Amortization of revaluation	679	800	(67)	1,412
Balance – December 31, 2012	225,137	213,738	26,760	465,635

The increase in inflation compensation interest is a result of the CPI rate change over the reference period.

Principal repayments

The principal repayments for the next years, excluding the revaluations, will be as follows:

	Principal repayments	Amortization of revaluation	Long-term debt
2013	65,331	(846)	64,485
2014	46,068	(1,505)	44,563
2015	24,488	(1,549)	22,939
2016	272,606	(1,601)	271,005
2017	25,485	(1,668)	23,817
Thereafter	895,565	(57,546)	838,019
	1,329,543	(64,715)	1,264,828

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

23. 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 $1,000 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.

The convertible debentures may not be redeemed by the Corporation on or before April 30, 2013 except in certain limited circumstances following a change of control. After 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, 2012	December 31, 2011
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	79,655	79,490
Equity portion of convertible debentures	1,340	1,340

24. CONTINGENT CONSIDERATIONS

	December 31, 2012	December 31, 2011
Balance at beginning of the year	3,887	—
Liability assumed as part of the business acquisitions (Note 5)	—	2,999
Liability (recovered) incurred	(357)	1,858
Contingent considerations paid	(983)	(1,147)
Accretion expense on contingent considerations (included in finance costs)	228	177
Balance at the end of the year	2,775	3,887
Current portion of contingent considerations	—	(983)
Non-current contingent considerations	2,775	2,904

Cloudworks

The Cloudworks Acquisition described in Note 5 b) provides for the potential payment of additional amounts to the vendors over a period of more than 40 years commencing on the acquisition date and ending on the 40th anniversary of the last project under development to achieve commercial operation (or the 50 years after the acquisition date if that date is earlier). Such potential deferred payments are divided into four categories: (i) deferred operating facilities payments, (ii) deferred development projects payments, (iii) deferred terminal value payment; and (iv) deferred prospective projects payments. 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.

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

The maximum aggregate amount of all deferred payments under the Cloudworks Acquisition is limited to a present value amount of $35,000 as at the acquisition date, and for the purpose of applying such maximum aggregate payment amount, the amount of any deferred payment made is discounted to its present value amount by applying a mutually agreed upon discount rate per annum. The Corporation has the right, at any time during the five-year period after the acquisition date to extinguish all its obligations to make deferred payments by making a one-time payment of the amount by which the maximum aggregate amount of deferred payments of $35,000 exceeds the present value of any deferred payments (discounted to their present value amounts by applying an agreed discount rate per annum) made prior to the exercise of such right by the Corporation.

Stardale project

In connection with the Stardale acquisition described in Note 5 c), 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 Stardale 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.

25. 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 change in the liability during the year is as follows:

	December 31, 2012	December 31, 2011
Beginning of year	3,858	2,384
New obligations and revisions in estimated cash flows	2,015	1,144
Accretion expense (included in finance costs)	222	330
End of year	6,095	3,858

The cash flows were discounted at rates between 4.11% to 4.62% as at December 31, 2012 (5.25% to 5.33% in 2011) to determine the obligations.

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 Shares Preferred Shares").

a) Common shares

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

b) Implementation of a 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. Shares purchased under the DRIP are currently subject to a discount of 2.5% on the stock price of the shares for participating shareholders.

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 Shares Preferred Shares at $25.00 per share for aggregate gross proceeds of $50,000.

Holders of the Series C Shares 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.

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

	December 31, 2012	December 31, 2011
Series A Preferred Shares		
3,400,000 shares, $ 25.00 each	85,000	85,000
Issuance costs	(3,257)	(3,257)
Net proceeds	81,743	81,743
Deferred tax	846	846
Net carrying value	82,589	82,589
Series C Preferred Shares		
2,000,000 shares, $ 25.00 each	50,000	—
Issuance costs	(2,046)	—
Net proceeds	47,954	—
Deferred tax	526	
Net carrying value	48,480	—
	131,069	82,589

d) Share-based payments

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.

On May 10, 2011, during the annual and special meeting of shareholders of the Corporation, the special resolution to increase the maximum number of common shares of the Corporation available for issuance pursuant to options granted under the stock option plan from 2,350,000 to 4,064,123 was adopted. 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.

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 (none in 2011) have been exercised, resulting in an additional number of common shares for an amount of $507. Following this transaction, an amount of $148 was reclassified from share based payment in equity to common share capital.

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

	December 31, 2012		December 31, 2011	
	Number of options (000's)	Weighted average exercise price ($)	Number of options (000's)	Weighted average exercise price ($)
Outstanding - beginning of year	2,677	9.97	1,842	10.02
Granted during the year	417	10.70	835	9.88
Exercised during the year	(58)	8.75	—	—
Cancelled during the year	(300)	10.25	—	—
Outstanding - end of year	2,736	10.08	2,677	9.97
Options exercisable - end of year	1,314	10.37	1,196	10.70

The following options were outstanding and exercisable as at December 31, 2012:

Outstanding		Exercisable		
Number of options (000's)	Exercise price ($)	Number of options (000's)	Exercise price ($)	Year of maturity
846	11.00	846	11.00	2017
810	9.88	203	9.88	2018
417	10.70	—	10.70	2019
663	8.75	265	8.75	2020
2,736		1,314		

The following options were outstanding and exercisable as at December 31, 2011:

Outstanding		Exercisable		
Number of options (000's)	Exercise price ($)	Number of options (000's)	Exercise price ($)	Year of maturity
1,034	11.00	1,034	11.00	2017
835	9.88	—	9.88	2018
808	8.75	162	8.75	2020
2,677		1,196		

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, 2012	December 31, 2011
Risk-free interest rate	1.36% to 2.74%	0.1% to 2.7%
Expected annual dividend	$0.58	$0.58
Expected life of options	4.67 to 6 years	0.1 to 6 years
Expected volatility	19% to 35%	20% to 40%

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 six years. Expected volatility is estimated by considering historic average share price volatility.

e) Reductions 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 10, 2011. This resulted in a decrease of $202,488 in 2011 of the shareholders' capital account and an increase of $202,488 in 2011 of the contributed surplus from reduction of capital on common shares account.

(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 December 31, 2012

Record date	Payment date	Dividends per common share ($)	Dividends per Series A Preferred share ($)
12/30/2011	1/16/2012	0.145	0.3125
3/30/2012	4/16/2012	0.145	0.3125
6/29/2012	7/16/2012	0.145	0.3125
9/28/2012	10/15/2012	0.145	0.3125
		0.580	1.25

For the year ended December 31, 2011

Record date	Payment date	Dividends per common share ($)	Dividends per Series A Preferred share ($)
12/31/2010	1/17/2011	0.145	0.4212
3/31/2011	4/15/2011	0.145	0.3125
6/30/2011	7/15/2011	0.145	0.3125
9/30/2011	10/17/2011	0.145	0.3125
		0.580	1.3587

28. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a) Changes in non-cash operating working capital items

	December 31, 2012	December 31, 2011
Accounts receivable	2,298	(19,479)
Prepaid and others	(563)	784
Accounts payable and other payables	(1,494)	(5,033)
	241	(23,728)

b) Additional information

	December 31, 2012	December 31, 2011
Interest paid (including $8,949 capitalized interest ($2,957 in 2011))	66,253	44,992
Non-cash transactions		
in unpaid property, plant and equipment	(14,937)	28,204
in unpaid development costs	977	9,008
in unpaid intangibles assets	27	(4)
in unpaid long-term assets	—	(50)
in unpaid issuance costs of preferred shares	396	—
in unpaid financing fees	—	(4)

29. 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 the consolidated statement of financial position date, 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 the consolidated statement of financial position date, 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 $9,126 lower than their estimated fair values based on the swap interest curve on December 31, 2012, increased by a risk premium ranging from 0.04% to 1.91% for a total ranging from 1.36% to 4.45%. The carrying values of the fixed-rate debts, the bonds and the debentures are approximately $90,428 lower than their estimated fair market values based on the swap interest curve on December 31, 2012, increased by a risk premium ranging from 0.04% to 4.43% for a total ranging from 1.36% to 6.99%.

(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 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 15.

The reserve accounts and related risks are described in detail in Note 16.

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 had a positive working capital of $83,425 as at December 31, 2012. If necessary, the Corporation can use its revolving credit term facility, as described in Note 22 a), of which $200,248 was available as at December 31, 2012 ($147,218 in 2011). 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 16) 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	14,643		
Accounts payable and other payables	32,532	8,805	
Income tax liabilities	708	833	
Current portion of derivative financial instruments	8,206	9,649	
Current portion of long-term debt	5,581	58,871	
Construction holdbacks			1,668
Derivative financial instruments			42,814
Accrual for acquisition of long-term assets			13,063
Long-term debt			442,824
Contingent considerations			1,565
Total	61,670	78,158	501,934

(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 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 partly 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 $10 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.

The Corporation holds foreign exchange contracts that enable it to eliminate the risk of any Euro appreciation against the Canadian dollar on equipment purchases. See Note 6 for more details.

30. COMMITMENTS AND CONTINGENCIES

(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 located in the Province of Quebec, up to the agreed maximum quantity for each of the hydroelectric facilities and wind farms. In return, the facilities are required to supply a minimum quantity of electricity during each of the consecutive 12-month periods beginning on December 1st of each year for the hydroelectric facilities and beginning on January 1st of each year for the wind farms. These agreements are renewable for identical periods at the option of the Corporation's subsidiaries, except for the wind farms.

Total revenues from Hydro-Québec amounted to $69,560 in 2012 ($57,637 in 2011), representing 38% of the Corporation's revenues (39% in 2011). 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 2050, 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 $73,842 in 2012 ($67,204 in 2011) representing 41% of the Corporation's revenues (45% in 2011). 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 $19,586 ($8,312 in 2011) representing 11% of the Corporation's revenues (6% in 2011).

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 $3,365 in 2012 ($2,733 in 2011), representing 2% of the Corporation's revenues (2% in 2011).

(b) Other Commitments

Wind farm facilities

A joint venture of the Corporation entered into a PPAs with Hydro-Québec. In order to fulfill its obligation under the power purchase agreement, the joint venture will need to develop and construct a facility. Collectively with its partner, the joint venture entered into various agreements related to the acquisition of the turbines, the construction and the operation of the wind farm.

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.

Ashlu Creek facility

First Nations agreements

Pursuant to an agreement with Ashlu Creek Investments Limited Partnership, the Squamish First Nation is entitled to a royalty based on revenues of the Ashlu Creek Project since the beginning of operations. The Squamish 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 the Squamish 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 in view of the expected 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.

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 $48,634 term loan described in Note 22 h).

Creek Power facility

Creek Power Inc. entered into several contracts in view of the expected construction of hydroelectric power-generating facilities.

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.

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

Umbata Falls facility

Dissolution of the partnership

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.

North West Stave facility

Construction contracts

North West Stave River Hydro LP, entered into various contracts for the construction of a hydroelectric power-generated facility. During construction, North West Stave has to pay a fixed amount to Douglas First Nations.

Royalties

North West Stave River Hydro LP, entered into an agreement to pay Douglas First Nations 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 60 years of the project. 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 in view of the expected construction of a power generating facility.

Operating leases

The Corporation is engaged under long-term operating leases of premises which will expire between 2015 and 2018.

Summary of commitments

As at December 31, 2012, the expected schedule of commitment payments is as follows:

Contractual obligations	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
2013	57,667	57,148	10,558	91,715	217,088
2014	79,749	12,962	10,472	17,017	120,200
2015	56,497	12,567	10,409	15,629	95,102
2016	74,963	46,213	10,340	206,951	338,467
2017	54,887	7,733	10,036	86,423	159,079
Thereafter	1,242,914	64,263	122,412	172,623	1,602,212
Total	1,566,677	200,886	174,227	590,358	2,532,148

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.

31. 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, solar farm and wind farms; 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 $1,000 on an annual basis in a major maintenance reserve account in order to fund any major maintenance of hydroelectric facilities, solar farm or wind farms 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 reserve account. This account 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 $2,021,688 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.

Future development and construction of new facilities and the development of the development projects and the 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 22 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.

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

32. RELATED PARTY TRANSACTIONS

In the fourth quarter of 2012, the parent of the Harrison Operating Facilities distributed $46,900 to its partners. The funds were distributed in the form of loans to the Corporation and its partners. The loans of $23,444 were presented as loans to partners as at December 31, 2012. It is expected that during the year of 2013, these loans will be reimbursed directly from a distribution from the parent of the Harrison Operating Facilities and a corresponding decrease in non-controlling interests will be recorded with no impact to cash flows.

33. SEGMENTED INFORMATION

Geographic segments

The Corporation has 21 hydroelectric facilities, five wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2012, operating revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $3,365 ($2,733 in 2011), representing a contribution of 2% for the year ended December 31, 2012, (2% in 2011) to the Corporation's consolidated operating 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:

For the years ended		December 31, 2012	December 31, 2011
Major customer	Segment		
British Columbia Hydro and Power authority	Hydroelectric generation	73,842	67,204
Hydro-Québec	Hydroelectric and wind power generation	69,560	57,637
Hydro One inc and its affiliates	Hydroelectric and solar generation	19,586	8,312
		162,988	133,153

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 facility to publicly owned utilities. Through its site development segment, it analyses potential sites and develops hydroelectric, wind and solar facility up to the commissioning stage.

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

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

The solar power generation segment was added following the beginning of commercial operation of the Stardale solar farm on May 15, 2012.

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

For the year ended December 31, 2012

Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Operating revenues	123,626	45,558	11,676	—	180,860
Expenses:					
Operating	20,640	7,960	533	—	29,133
General and administrative	5,451	2,252	278	1,751	9,732
Prospective project expenses	—	—	—	4,412	4,412
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses and unrealized net gain on derivative financial instruments	97,535	35,346	10,865	(6,163)	137,583
Finance costs					63,281
Other net expenses					15,527
Earnings before income taxes, depreciation, amortization and unrealized net gain on derivative financial instruments					58,775
Depreciation					43,902
Amortization					21,835
Unrealized net gain on derivative financial instruments					(8,342)
Earnings before income taxes					1,380

As at December 31, 2012					
Goodwill	8,269	—	—	—	8,269
Total assets	1,322,173	423,634	139,222	438,924	2,323,953
Total liabilities	836,859	383,435	144,555	271,172	1,636,021
Additions of property, plant and equipment	612	3,682	153	169,449	173,896

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

For the year ended December 31, 2011

Operating segments	Hydroelectric generation	Wind power generation	Site development	Total
Operating revenues	117,342	30,918	—	148,260
Expenses:				
Operating	18,174	6,052	—	24,226
General and administrative	4,297	1,987	4,081	10,365
Prospective project expenses	—	—	2,473	2,473
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses and unrealized net loss on derivative financial instruments	94,871	22,879	(6,554)	111,196
Finance costs				53,122
Other net expenses				2,693
Earnings before income taxes, depreciation, amortization and unrealized net loss on derivative financial instruments				55,381
Depreciation				31,177
Amortization				19,793
Unrealized net loss on derivative financial instruments				61,479
Loss before income taxes				(57,068)

As at December 31, 2011				
Goodwill	8,269	—	—	8,269
Total assets	1,310,207	387,099	336,103	2,033,409
Total liabilities	838,575	324,270	291,448	1,454,293
Additions of property, plant and equipment	1,305	484	192,396	194,185

34. JOINT VENTURE OPERATIONS

The Corporation's has the following significant interests in joint ventures:

a. A 38% proportionate share of the assets, liabilities, revenues and expenses of the joint venture of Baie-des-Sables, L'Anse-à-Valleau, Carleton, Gros-Morne and Montagne-Sèche wind farms;

b. A 49% proportionate share of the assets, liabilities, revenues and expenses, of the joint venture of Umbata Falls;

c. A 50% proportionate share of the assets, liabilities, revenues and expenses of the joint venture of Viger-Denonville.

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

The following amounts are included in the Corporation consolidated financial statements as a result of the proportionate consolidation of entities described in a), b) and c):

The proportionate interest is as follows:	December 31, 2012	December 31, 2011
Assets		
Current	31,459	30,500
Non-current	374,629	353,451
Total assets	406,088	383,951
Liabilities		
Current	7,171	4,140
Non-current	37,724	53,024
Total liabilities	44,895	57,164

The proportionate interest is as follows:	December 31, 2012	December 31, 2011
Results		
Revenues	49,762	34,407
Expenses	32,236	26,333
Net earnings	17,526	8,074

35. SUBSEQUENT EVENTS

a) Dividends

Date of announcement	Record date	Payment date	Dividends per common share ($)	Dividends per Series A Preferred Share ($)	Dividends per Series C Preferred Share ($)
03/14/2013	03/28/2013	04/15/2013	0.1450	0.3125	0.4923

b) Viger-Denonville

On February 23, 2013, the Viger-Denonville wind farm project gave the Engineering, Procurement and Construction contractor a notice to proceed, which was shortly followed by the Certificate of Authorization to start construction given by the Ministère du Développement durable, de l'Environnement, de la Faune et des Parcs.

INFORMATION FOR INVESTORS

Stock Exchange Listing

Common shares of Innergex Renewable Energy Inc. are listed on the Toronto Stock Exchange (TSX) under the symbol INE.
Series A Preferred Shares of the Corporation are listed on the TSX under the symbol INE.PR.A.
Series C Preferred Shares of the Corporation are listed on the TSX under the symbol INE.PR.C.
Convertible debentures of the Corporation are listed on the TSX under the symbol INE.DB.

Innergex Renewable Energy Inc. is a constituent of the following market indices:

- S&P/TSX SmallCap Index
- S&P/TSX Clean Technology Index.

Series A Preferred Shares (TSX: INE.PR.A)

Innergex Renewable Energy Inc. currently has 3.4 million 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 Corporation prior to January 15, 2016.

Series C Preferred Shares (TSX: INE.PR.C)

Innergex Renewable Energy Inc. currently has 2.0 million 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 Corporation 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 Corporation at a price of $10.65 per share at the holder's option at any time prior to the earlier of April 30, 2017 and the redemption date specified by the Corporation (no earlier than April 30, 2013, except in certain limited circumstances). The convertible debentures are subordinated to all other indebtedness of the Corporation.

Credit Ratings

	Standard & Poor's	DBRS
Innergex Renewable Energy Inc.	BBB-	BBB (low)
Series A Preferred Shares	P-3	Pfd-3 (low)
Series C Preferred Shares	P-3	Pfd-3 (low)
Convertible debentures	--	--

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 Corporation's transfer agent and registrar:

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

INFORMATION FOR INVESTORS

Dividend Reinvestment Plan (DRIP)

Innergex Renewable Energy Inc. implemented a Dividend Reinvestment Plan ("DRIP") for its common shareholders, which came into effect on August 31, 2012 and 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 Company's DRIP, please visit the Corporation's website at www.innergex.com or contact the DRIP administrator, Computershare Trust Company of Canada.

Please note that if you wish to enroll in the DRIP but own your shares indirectly through a broker or financial institution, you must contact this intermediary and ask them to enroll in the DRIP on your behalf.

Independent Auditor

Deloitte s.e.n.c.r.l.

Common Share Dividend Policy and Payment History

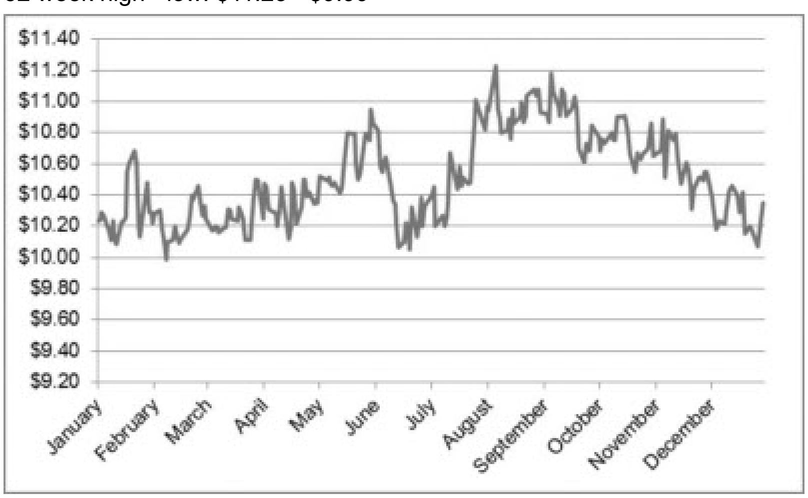
As publicly disclosed, Innergex Renewable Energy Inc. intends to pay an annual dividend of $0.58 per common share, payable on a quarterly basis.

Payment History	2012	2011	2010
First Quarter	$0.145	$0.145	See note 1
Second Quarter	$0.145	$0.145	$0.148181
Third Quarter	$0.145	$0.145	$0.145
Fourth Quarter	$0.145	$0.145	$0.145

[1]The Corporation adopted its common share dividend policy in March 2010, upon completion of the strategic combination by plan of arrangement of Innergex Power Income Fund and Innergex Renewable Energy Inc. The dividend declared for the second quarter of 2010 was prorated to reflect the adoption of an annual dividend of $0.58 per share.

Stock Chart: January 1 - December 31, 2012

52 week high - low: $11.23 - $9.99



INFORMATION FOR INVESTORS

Annual Shareholders' Meeting
The annual shareholders' meeting will be held on:

Tuesday, May 14, 2013, at 4:00 p.m. EDT
At the Hyatt Regency Hotel
1255, rue Jeanne-Mance
Montreal (Québec) H5B 1E5

Innergex Renewable Energy Inc.'s *Notice of Annual Meeting of Shareholders and Management Information Circular - Solicitation of Proxies* will be available as of April 18, 2013 on the Investors page of our Website, under Continuous Disclosure Documents. Hard copies are available upon request.

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
450-928-2550
mjprivyk@innergex.com

Or visit www.innergex.com.

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

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