INNERGEX

Renewable Energy.
Sustainable Development.

ANNUAL REPORT

at December 31, 2019

BUILDING A BETTER WORLD WITH **RENEWABLE ENERGY**

For 30 years now, Innergex believes in a world where abundant renewable energy promotes healthier communities and creates shared prosperity. As an independent renewable power producer that develops, acquires, owns and operates hydroelectric facilities, wind farms and solar farms, Innergex is convinced that generating power from renewable sources will lead the way to a better world.

30 years of accomplishments

We will continue to generate value for our employees, shareholders, partners and host communities today to contribute to a more sustainable world for future generations. We remain committed to responsible growth that balances people, our planet, and prosperity. Innergex generates renewable energy in Canada, the United States, France and Chile.

The Corporation's shares are listed on the Toronto Stock Exchange under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures are listed under the symbols INE.DB.B and INE.DB.C.

100% RENEWABLE ENERGY

4 **countries where we conduct operations**
Canada, United States, France, Chile

5 **offices worldwide**
Longueuil and Vancouver in Canada, San Diego in the United States, Lyon in France and Santiago in Chile

25 **projects built**

43 **projects acquired**

68 **operating facilities in our portfolio of assets**

410 **employees**[1]

3,488 **MW of total gross installed capacity**

[1] Including employees from Energía Llaima

FINANCIAL HIGHLIGHTS

- Production was 96% of the long-term average ("LTA") for the year ended December 31, 2019.
- Revenues increased 16% to $557.0 million for the year ended December 31, 2019.
- Adjusted EBITDA rose 16% to $409.2 million for the year ended December 31, 2019, corresponding to an Adjusted EBITDA Margin of 73.5%.
- Adjusted EBITDA Proportionate increased 21% to $516.8 million for the year ended December 31, 2019.
- Full commissioning of the Foard City wind farm on September 27, 2019 and the Phoebe solar farm on November 19, 2019.
- Signing of a long-term Power Purchase Agreement for the Hillcrest Solar Project in Ohio, USA on November 28, 2019.
- On February 6, 2020, Innergex and Hydro-Québec announced a $661 million Private Placement and a Strategic Alliance.

	Year ended December 31[1]		
	2019	2018	2017
OPERATING RESULTS			
Production (MWh)	6,509,622	5,086,497	4,394,210
Revenues	557,042	481,418	400,263
Adjusted EBITDA[2]	409,175	352,179	298,728
Adjusted EBITDA Margin[2]	73.5%	73.2%	74.6%
Net (Loss) Earnings From Continuing Operations	(53,026)	26,215	19,136
Net (Loss) Earnings	(31,211)	25,718	19,136
Adjusted Net (Loss) Earnings From Continuing Operations[2]	(25,817)	13,963	15,662
PROPORTIONATE			
Production Proportionate (MWh)[2]	8,021,758	6,361,733	4,497,943
Revenues Proportionate[2]	660,941	564,686	411,468
Adjusted EBITDA Proportionate[2]	516,819	428,684	308,343
COMMON SHARES			
Dividends declared on common shares	95,046	90,215	71,621
Weighted Average Number of Common Shares (in 000s)	134,658	130,030	108,427
CASH FLOW AND PAYOUT RATIO			
Cash Flow From Operating Activities	240,065	209,390	192,451
Free Cash Flow[2,3]	93,311	105,124	87,207
Payout Ratio[2,3]	102%	86%	82%
Adjusted Payout Ratio[2,3]	88%	66%	64%

	As at December 31		
	2019	2018	2017
FINANCIAL POSITION			
Total Assets	6,372,104	6,516,158	4,190,456
Total Liabilities	5,756,778	5,574,121	3,737,194
Non-Controlling Interests	10,942	312,776	14,920
Equity Attributable to Owners	604,384	629,261	438,342

1. Results from continuing operations unless otherwise indicated.
2. Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted Net Earnings (Loss) from continuing operations, Production Proportionate, Revenues Proportionate, Adjusted EBITDA Proportionate, Free Cash Flow, Payout Ratio and Adjusted Payout Ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production Proportionate is a key performance indicator for the Corporation that cannot be reconciled with an IFRS measure. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
3. For more information on the calculation and explanation, please refer to the "Free Cash Flow and Payout Ratio" section.

BALANCING PEOPLE, OUR PLANET AND PROSPERITY TO **BUILD A BETTER WORLD**

We are guided by our philosophy of sustainable growth that balances people, our planet and prosperity. By harnessing the power of the sun's rays, the natural flow of water and the motion of the air, we continue to focus our actions on fighting climate change to generate a greener future.

Our value is generated from the balance between these three shared beliefs and we remain convinced that focusing on renewable energy, while balancing the three Ps, will lead the way to a better world for future generations.

PEOPLE
A passion to make a difference

Our growing and diverse team attracts skilled and passionate people who share a commitment to create a better world. Together, we achieve our mission by driving opportunities, acting with integrity and following our passion. Our employees have enabled Innergex to not only become one of the largest independent renewable energy producers in Canada, but have positioned us as a global player in the renewable energy sector.

Investing in equal opportunities for a more balanced workplace, we are proud to have

26% **OF WOMEN** **officers and**

46% **OF WOMEN** **in other management positions**

Our employees receive fair and competitive compensation with

$38 MILLION

in employee wages and benefits paid out in 2019

Became a signatory in the

EQUAL BY 30 **CAMPAIGN**

which promotes equal pay, equal leadership and equal opportunities for women in the clean energy sector by 2030

Conducted Innergex's **first employee survey** of full-time permanent and fixed-term employees with a

RESPONSE RATE OF 84%

PLANET
Renewable energy for a greener future

Since our beginning, we have understood the responsibility and opportunity we have in building a better world for future generations. By generating renewable energy exclusively, Innergex has remained well positioned to lead the transition to a carbon-neutral economy and is more optimistic than ever about the opportunities that lie ahead to do even more. Our development is conducted in harmony with the environment to harness the power that will continue to drive solutions for a better world.

In their operation, our facilities do not emit significant amounts of Greenhouse Gases (GHG) and they also produce electricity that offsets GHG emissions.

The annual GHG emissions offset by Innergex's production of clean, renewable energy in 2019 was approximately

5,670,558

METRIC TONNES OF CO_2

avoided, or the equivalent of removing 1,203,940 gasoline passenger vehicles from roads[1]

Building a better world with renewable energy is our mission.

In 2019, we supplied the equivalent of

850,359

HOUSEHOLDS

with clean, renewable energy[2]

Our environmental team manages the ecological health of

329,366

SQUARE METRES

(the equivalent of 61 football fields) of fish habitat created to offset temporary impacts from construction activities and any longer term impacts that could arise from operation

We successfully phased out plastic water bottles provided to employees at

ALL

OUR OFFICES

and replaced them with bottleless coolers that provide filtered carbonated and un-carbonated water directly from tap

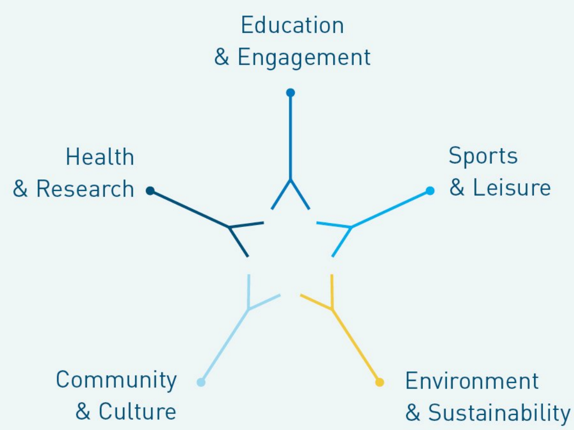
[1] Based on Innergex's 2019 Production Proportionate of 8,021,758 MWh and calculated through https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.
[2] Based on Innergex's 2019 Production Proportionate in each country in which we operate, divided by the local average household consumption, with data from the World Energy Council (2014).

PROSPERITY
Generating wealth through strategic growth

We focus on developing projects that create long-term value and promote Innergex's sustainable growth, while maintaining the integrity of our existing assets. We are proud of the trust we have earned with the communities in which we operate, our partners, and our shareholders, and will continue to deliver long-term value through strategic and innovative investment opportunities. At Innergex, our prosperity shares economic benefits, and creates sustainable economic development opportunities and quality jobs.

In 2019, our sponsorship and donation program

BENEFITTED
174
ORGANIZATIONS



1,229,188
PERSON HOURS
worked on two construction projects in 2019

In 2019, Innergex declared more than
$95 MILLION
IN DIVIDENDS
on common shares

In 2019, we added
600
MW (gross)
of renewable energy
to our growing portfolio

Began construction on the $125 million **Innavik hydro project**, a
50-50
PARTNERSHIP
with the Inuit community of Inukjuak with a 40-year PPA

Rooted in Ethics, **DRIVEN BY EXPERIENCE**

Our mission of building a better world with renewable energy is the foundation of our development strategy and, together with our values, it guides what we do everyday. Our Governance sets the tone, example and structure that not only promotes sustainable corporate growth for our shareholders, employees and partners, but enables us to affect positive social and environmental change. The experienced, committed and uniquely skilled members of our Board of Directors set the strategic direction that has, and will continue to, position Innergex as a respected, trusted and innovative leader in the sector. Our internal policies, beginning with the Code of Conduct, set the basic principles that ensure that every member of the Innergex team conducts themselves with the utmost integrity and respect in all matters.

In 2019, our experienced Board of Directors consists of

9 **MEMBERS**

who guide the Corporation to ensure responsible and sustainable shareholder growth

88% OF OUR BOARD MEMBERS ARE **INDEPENDENT**

The Policy Regarding Board Diversity is Innergex's commitment to the value of diversity of gender and the Corporation is proud that at the end of 2019

33% **OF MEMBERS** ON THE BOARD **were women**

THE AVERAGE **AGE**

of the Board of Directors at the end 2019 was

62

In 2019, the percentage of

COMBINED **ATTENDANCE**

at board and committee meetings was

98%

There are

15 POLICIES

to ensure compliance with the highest ESG standards,

4 **of which were revised and updated in 2019**

MESSAGE TO SHAREHOLDERS

30 YEARS OF BUILDING A BETTER WORLD

2020 marks our 30th year as custodians of the planet. From day one, our efforts have focused on producing energy from renewable sources in support of a greener future. We take pride in our contribution in building a better world thanks to renewable energy, while generating significant, positive benefits for the Three Ps: People, our Planet and Prosperity. With a net installed capacity of 2,588 MW comprised exclusively of renewable energy, well above our 2020 objective of 2,000 MW, it is with boundless optimism that we enter this new decade.

2019 may go down in history as the year in which climate change became a fundamental issue. The world's youth have mobilized to deliver a strong message which we hope will serve as wake-up call for key decision-makers and corporations. As for Innergex, we view this message as an urge to pursue our development efforts in harmony with nature. Our sustainable growth model has produced and continues to generate shareholder value while delivering benefits that we share with communities. Our Three Ps philosophy, therefore, inspires us to lead this path.

OUR ACTIONS

The year 2019 was marked by the sale of our participation in HS Orka and the completion of two major projects. We launched **Foard City**, our largest wind farm project to date, with an installed capacity of 350 MW, as well as a massive 250 MW solar farm, **Phoebe**, in Texas. These two major projects confirmed our ability to deliver projects on time and on budget. The experience acquired in the solar energy sector will serve us well as we pursue the development of this technology in the U.S.

We have also begun work on the **Innavik** hydroelectric generating station in Nunavik, in Quebec's Far North region, which is expected to be commissioned by 2022. This 7.5 MW project symbolizes everything we believe in. This generating station is being developed in a 50-50 partnership with the Pituvik Landholding Corporation, an entity stemming from the Inuit community responsible for undertaking this project, which is in complete harmony with nature. In addition, this project will act as a lever for the sustainable development of the community.

Solar energy is an increasingly important component in our development prospects. In Ohio, we signed a power purchase agreement with a major partner for clean energy produced by our 200 MW **Hillcrest** solar project, which is currently under construction. In Hawaii, development continues on our **Paeahu** and **Hale Kuawehi** integrated solar and battery storage projects to help decarbonize the energy supply of their respective islands, which are otherwise supplied by fossil fuel generation.

OUR PROJECTS

The growth that we have experienced over the past few years has allowed us to consolidate our hydro, wind and solar power expertise in a growing number of markets, and sustainability will continue to be the driving force behind all future development. In keeping with our diversification strategy, Phoebe has allowed us to substantially increase our installed solar capacity over the past year. Consequently, we can offer technologies tailored to local renewable resources and markets, thus compensating for variables such as weather in markets where our activities are concentrated.

The **U.S.** represents a vast, growing market, and we plan to develop several solar projects in various regions of the country. Consequently, we have undertaken initiatives to procure solar panels in the U.S. before the current tax incentives expire.

We will continue our development initiatives in **France**, as there are numerous opportunities in wind power and other renewable energies. Although project development may take longer than in other markets, we strongly believe in France's potential, given the ambitious green energy objectives that are in place. For example, our partnership with Vent d'Est allows us to draw on additional wind energy development expertise.

We also see enormous potential in **Chile and elsewhere in Latin America**, where a variety of renewable energy solutions are in demand. Development opportunities in **Canada**, mainly in provinces other than those where we are currently active, remain on our agenda, but they are evolving at different speeds according to local imperatives.

In addition to renewable power generation, we are closely monitoring advancements in technology and the evolution of renewable energy markets. We know that the electricity market will evolve beyond the traditional "production, transportation and consumption" model. **Energy storage**, which we are deploying in our Hawaii projects, represents an important evolution that we intend to master. Costs continue to drop, and the development of new technologies is steadily progressing, which is very promising. Globally, we are encouraged by the new ways of viewing the procurement of renewable energy as a means to reduce carbon emissions.

In February 2020, we have announced the creation of a Strategic Alliance with **Hydro-Québec**. The Alliance will enable us to realize co-investments to accelerate the development of renewable energy by combining Innergex's know-how, notably of international markets, with that of Hydro-Québec, for instance in battery storage. Thanks to our new main shareholder Hydro-Québec, we have access to extra means that will enable us to realize clean energy projects that are larger and more diversified, always respecting the sustainable development principles we hold dear.

OUR PEOPLE

Our 3 Ps philosophy – People, Planet and Prosperity – guides our actions and ensures our sustainable growth. We are proud to have launched new communication tools in 2019 that detail tangible examples of the steps we are taking to improve the environment, society and our own governance.

We are fortunate to be able to count on a passionate and talented team whose members work hard, day in and day out, to build a better world. We promote a culture that creates a safe, healthy and supportive environment for everyone to grow. Our extended family is comprised of over 410 employees, who enable us to efficiently operate our high-value assets and continue to evolve. Thank you for your daily efforts.

We also draw inspiration from our numerous, outstanding community partnerships. We believe that sustainable development, above and beyond the shared respect for the environment, is also about the well-being of host communities, our partners and all other stakeholders involved in our projects. The positive impact of our facilities on local communities is a difference maker, which validates the relevance of our approach and values. Thank you for welcoming us into your homes and placing your trust with us.

Investors are increasingly interested in supporting the growth of renewable energy, a thriving industry. As we reach the milestone of 8 TWh of clean electricity, we are well positioned to substantially increase our sustainable development initiatives to the greater benefit of all. We thank you for believing in our development approach.

To all our shareholders, customers, financial partners, suppliers, business partners and all other stakeholders, thank you for your support and for being part of the solution.

As we celebrate our 30th year of existence, we are more determined than ever to focus on sustainable growth as a mean to fight climate change. Our mission is clear, and we believe in it. It is time for optimism.

Jean La Couture
Chairman of the Board

Michel Letellier
President and Chief Executive Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") is a discussion of the operating results, cash flows and financial position of Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") for the three- and twelve-month periods ended December 31, 2019, and reflects all material events up to February 27, 2020, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the audited consolidated financial statements and the accompanying notes for the year ended December 31, 2019.

The audited consolidated financial statements attached to this MD&A and the accompanying notes for the year ended December 31, 2019, along with the 2018 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). However, some measures referred to in this MD&A are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

All tabular dollar amounts are in thousands of Canadian dollars, except amounts per share or unless otherwise indicated. Some amounts included in this MD&A have been rounded to make reading easier, which may affect some calculations.

To inform readers of the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws ("Forward-Looking Information"). Please refer to the "Forward-Looking Information" section for more information.

Additional information relating to Innergex, including its Annual Information Form, can be found on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at sedar.com or on the Corporation's website at innergex.com. Information contained in or otherwise accessible through our website does not form part of this MD&A and is not incorporated into the MD&A by reference.

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OVERVIEW

The Corporation is a developer, acquirer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind and solar power that benefit from simple, proven technologies.

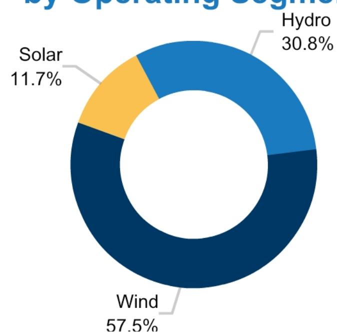
Discontinued Operations
On May 23, 2019, the Corporation announced completion of the sale of its wholly owned subsidiary Magma Energy Sweden A.B. ("Magma Sweden"), which owns an equity interest of approximately 53.9% in HS Orka hf ("HS Orka"), owner of two geothermal facilities in operation, one hydro project in development and prospective projects in Iceland. The Geothermal Power Generation Segment is now accounted for as discontinued operations. For more information, please refer to the "Discontinued Operations" section of this MD&A. The figures presented in this MD&A are for the continuing operations unless otherwise indicated.

Segments

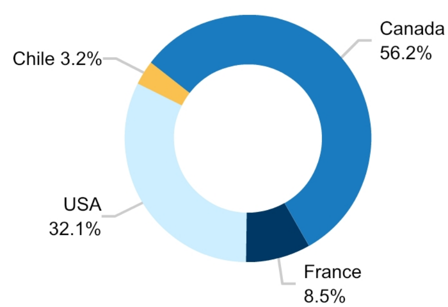
As at December 31, 2019, the Corporation has three operating segments and four geographic segments.

Operating Segments	Geographic Segments
Hydroelectric Power Generation	Canada
Wind Power Generation	France
Solar Power Generation	United States
	Chile

Net Installed Capacity by Operating Segment



Net Installed Capacity by Geographic Segment



Portfolio of Assets

As at the date of this MD&A, the Corporation owns interests in three groups of projects at various stages: the Operating Facilities, the Development Projects and the Prospective Projects.

Operating Facilities
The Corporation owns and operates 68 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1992 and November 2019, the facilities have a weighted average age of approximately 7.0 years.

They mostly sell the generated power under long-term power purchase agreements, power hedge contracts[1] and short- and long-term industrial contracts (each, a "PPA") to rated public utilities or other creditworthy counterparties or on the open market. The PPAs have a weighted average remaining life of 15.3 years (based on gross long-term average production).

For most Operating Facilities in Canada and in France, PPAs include a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery. For most Operating Facilities in the United States, power generated is sold through PPAs or on the open market supported by financial or physical power hedges. In Chile, Operating Facilities sell the power generated through PPAs to industrial customers or on the open market.

[1] A power hedge contract is deemed a PPA regardless of whether it is subjected to hedge accounting or accounted for as a financial derivative at fair value through earnings (loss).

	Number of Operating Facilities[1]	Installed Capacity (MW)	
		Gross[2]	Net[3]
HYDRO			
Canada	33	1,019	713
United States	1	10	10
Chile	3	152	74
Subtotal	37	1,181	797
WIND			
Canada	8	908	714
France	15	317	221
United States	3	754	554
Subtotal	26	1,979	1,489
SOLAR			
Canada	1	27	27
United States	3	267	266
Chile	1	34	9
Subtotal	5	328	302
Total	68	3,488	2,588

1. The number of Operating Facilities includes all facilities owned and operated by the Corporation, including non-wholly owned subsidiaries and joint ventures and associates.
2. Gross installed capacity is the total capacity of all Operating Facilities of Innergex, including non-wholly owned subsidiaries and joint ventures and associates.
3. Net installed capacity is the proportional share of the total capacity attributable to Innergex based on its ownership interest in each facility.

PPA Renewals

On April 16, 2018, the Corporation and the Sekw'el'was Cayoose Creek Band announced that they reached an agreement with the British Columbia Hydro and Power Authority ("BC Hydro") for the renewal of the Walden North Facility's PPA (the "Walden PPA"). The renewed Walden PPA became effective as of April 1, 2018 and has a 40-year term. The Walden PPA is subject to approval by the British Columbia Utilities Commission ("BCUC").

On April 16, 2018, the Corporation announced that it reached an agreement with BC Hydro for the renewal of the PPA of the Brown Lake Facility for a 40-year term (the "Brown Lake PPA"). The renewed Brown Lake PPA became effective as of April 1, 2018 and is subject to approval by the BCUC.

By Order G-278-19, dated November 8, 2019 ("BCUC Order"), in the absence of an updated and approved Integrated Resource Plan from BC Hydro ("IRP"), the BCUC declined to make any determination with regards to whether the Walden PPA and the Brown Lake PPA are, as of the date of the BCUC Order, in the public interest. However, the BCUC is prepared to consider accepting

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

PPA renewals for periods shorter than 40 years to allow for the conclusion of BC Hydro's next IRP proceeding, at which time there may be further clarity on BC Hydro's long-term energy needs and supply alternatives to meet demand. Accordingly, the BCUC adjourned the Walden PPA and the Brown Lake PPA approval application proceeding for 60 days from the date of the BCUC Order to allow the parties to the Walden PPA and the Brown Lake PPA to restructure and resubmit to the BCUC new electricity purchase agreements with a term not to exceed three years from the date of the BCUC Order. At BC Hydro's request, the BCUC subsequently extended the adjournment period for an additional 45 days. As of the date of this MD&A, the parties to the Brown Lake PPA are considering resubmitting to the BCUC a restructured Brown Lake PPA with a term of no more than three years from the date of the BCUC Order, whereas the parties to the Walden PPA are considering, for the time being, not to resubmit a restructured Walden PPA to the BCUC.

The first PPA for the Sainte-Marguerite hydro facility, located in Quebec, reached its initial 25-year term in December 2018 and the Corporation has sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 25-year term. Discussions on the renewal terms and conditions are underway.

The first PPA for the Chaudière hydro facility, located in Quebec, reached its initial 20-year term in March 2019 and the Corporation has sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 20-year term. On August 30, 2019, the renewal of the PPA was signed for a 20-year term ending in March 2039.

The first PPA for the Montmagny hydro facility, located in Quebec, will reach the end of its initial 25-year term in May 2021 and the Corporation has sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 25-year term. Discussions on the renewal terms and conditions will take place during the year.

Development Projects

With the commissioning of the Foard City wind farm and of the Phoebe solar farm, the Corporation now holds interests in seven projects under development. Two Development Projects are currently under construction. These projects are scheduled to begin commercial operation between 2020 and 2022 (the "Development Projects"). For more information on the Development Projects, please refer to the "2019 Highlights" section.

	Number of Development Projects	Installed Capacity (MW)	
		Gross[1]	Net[2]
HYDRO			
Quebec	1	8	4
Chile	2	125	47
Subtotal	3	133	51
WIND			
France	1	7	5
SOLAR			
United States	3	245	245
Total	7	385	301

1. Gross installed capacity is the total capacity of all Development Projects of Innergex, including non-wholly owned subsidiaries and joint ventures and associates.
2. Net installed capacity is the proportional share of the total capacity attributable to Innergex based on its ownership interest in each facility.

Prospective Projects

The Corporation also owns interests in numerous prospective projects at various stages of development. Some have secured land rights, for which an investigative permit application has been filed or for which a proposal has been or could be submitted under a Request for Proposal or a Standing Offer Program (collectively the "Prospective Projects"). The list of Prospective Projects is revised annually to add or remove projects, according to their advancement potential.

There is no certainty that any Prospective Project will be realized.

	Prospective Projects Gross Projected Capacity (MW)[1]			
	Hydro	Wind	Solar	Total
Canada	730	4,343	320	5,393
United States	—	525	669	1,194
France	—	296	—	296
Chile	191	9	32	232
Total	921	5,173	1,021	7,115

1. Only Gross Installed Capacity is disclosed for Prospective Projects as the net capacity is not yet defined at this stage.

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

Shared Ownership

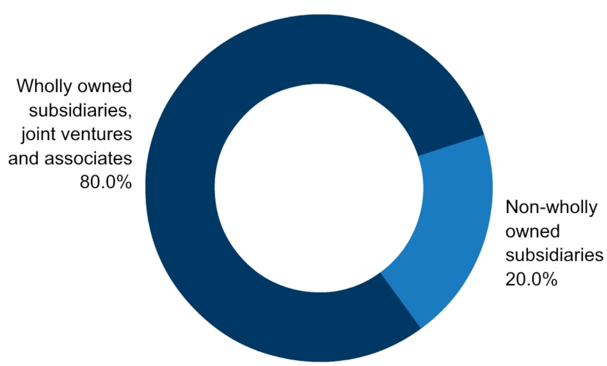
The Corporation shares ownership of some Operating Facilities, Development Projects and Prospective Projects with a corporate, financial, local community or Indigenous partner.

Non-Wholly Owned Subsidiaries
Some Operating Facilities have material non-controlling interests and are treated as non-wholly owned subsidiaries. These facilities' results are included in the Corporation's consolidated results.

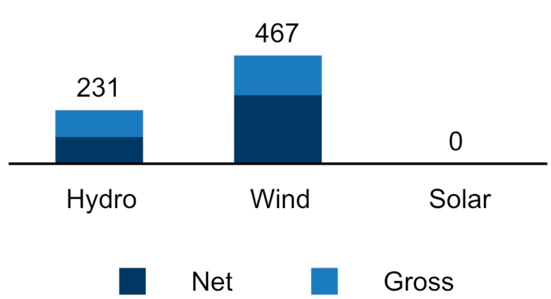
	Operating Facilities	Gross Installed Capacity (MW)	Net Installed Capacity (MW)	Sources of Energy	Principal Place of Operation	Proportion of Ownership Interest and Voting Rights Held by the Corporation December 31, 2019
Harrison Hydro Limited Partnership and its subsidiaries	Douglas Creek, Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River	150	75	Hydro	British Columbia	50.01%
Kwoiek Creek Resources Limited Partnership	Kwoiek Creek	50	25	Hydro	British Columbia	50.00% [1]
Innergex Sainte-Marguerite S.E.C.	Sainte-Marguerite	31	15	Hydro	Quebec	50.01%
Innergex Europe (2015) Limited Partnership and its subsidiaries	15 wind farms located in France	317	221	Wind	France	69.55%
Mesgi'g Ugju's'n (MU) Wind Farm L.P.	Mesgi'g Ugju's'n	150	75	Wind	Quebec	50.00% [1,2]
		698	411			

1. The Corporation owns more than 50% of the economic interest in the subsidiary.
2. The Corporation owns a 50% voting interest and a participation interest of 72.4% in 2019 (participation interest to decline over the years).

Gross Installed Capacity Attributable to Non-Wholly Owned Subsidiaries



Installed Capacity of Non-Wholly Owned Subsidiaries by Operating Segment



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

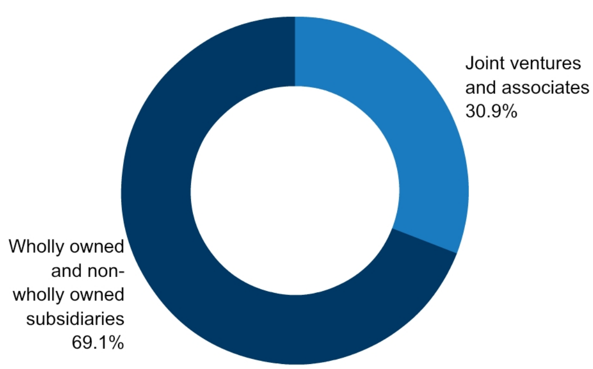
Joint Ventures and Associates

Some Operating Facilities are treated as joint ventures and associates and accounted for using the equity method. Innergex's share of Production, Revenues and Adjusted EBITDA of the joint ventures and associates are included in the Corporation's proportionate measures. For more information, please refer to the "Non-IFRS Measures" section.

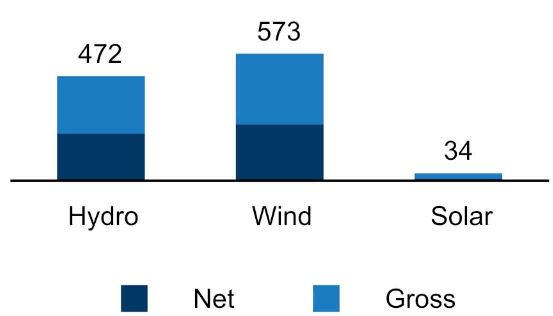
	Operating Facilities	Gross Installed Capacity (MW)	Net Installed Capacity (MW)	Sources of Energy	Principal Place of Operation	Proportion of Ownership Interest and Voting Rights Held by the Corporation December 31, 2019
Toba Montrose General Partnership	East Toba and Montrose Creek	235	94	Hydro	British Columbia	40.00% [1]
Shannon Group Holdings, LLC	Shannon	204	102	Wind	Texas	50.00%
Flat Top Group Holdings, LLC	Flat Top	200	102	Wind	Texas	51.00% [2]
Dokie General Partnership	Dokie	144	37	Wind	British Columbia	25.50%
Jimmie Creek Limited Partnership	Jimmie Creek	62	32	Hydro	British Columbia	50.99% [2]
Energía Llaima SpA	Guayacán, Peuchén, Mampil and Pampa Elvira	186	84	Hydro Solar	Chile	50.00%
Umbata Falls L.P.	Umbata Falls	23	11	Hydro	Ontario	49.00%
Parc éolien communautaire Viger-Denonville, S.E.C.	Viger-Denonville	25	12	Wind	Quebec	50.00%
		1,079	474			

1. The Corporation holds a 51% voting interest and 40% participating economic interest. In 2046, the Corporation's economic interest will increase to 51% for no additional consideration.
2. The Corporation does not consolidate the entity as it does not have complete control over the decision-making process.

Gross Installed Capacity Attributable to Joint Ventures and Associates



Installed Capacity of Joint Ventures and Associates by Operating Segment



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

Tax Equity Investment

The Corporation owns equity interests in some facilities that are eligible for tax incentives available for renewable energy facilities in the United States. With its current portfolio of renewable energy facilities, Innergex cannot fully monetize such tax incentives. To take full advantage of these incentives, the Corporation partners with Tax Equity Investors ("TEI") who invest in these facilities in exchange for a share of the tax credits.

Some TEI financing structures include a partial pay as you go ("Pay-go") funding arrangement under which, when the actual annual MWh production exceeds a certain production threshold, the TEI are obligated to make a cash contribution ("Pay-go Contribution") to the Corporation. The Pay-go arrangement resulted in a lower initial investment by the TEI and provides them with some protection from potential underperformance of the asset.

Innergex recognizes the TEI contributions as long-term loans and borrowings, at an amount representing the proceeds received from the tax equity investor in exchange for shares of the subsidiary, net of the following elements:

Elements affecting amortized cost of the tax equity financing	Description
Production Tax Credits ("PTC")	Allocation of PTCs to the tax equity investor derived from the power generated during the period and recognized in other (income) expenses as incurred
Investment Tax Credits ("ITC")	Allocation of ITCs to the tax equity investor stemming from the construction activities and recognized as a reduction in the cost of the assets to which they relate
Taxable income (loss), including tax attributes such as accelerated tax depreciation	Allocation of taxable income and other tax attributes to the tax equity investor recognized in other (income) expenses as incurred
Pay-go contributions	Additional cash contributions made by the tax equity investor when the annual production exceeds the contractually determined threshold
Cash distributions	Cash allocation to the tax equity investor

Production Tax Credit Program ("PTC")

Current United States tax law allows wind energy facilities to receive tax credits that are created for each MWh of generation for the first 10 years of the facility's operation. The TEIs are allocated a portion of the renewable energy facility's taxable income (losses) and PTCs produced and a portion of the cash generated by the facility until they achieve an agreed-upon after-tax investment return ("Flip Point"). After the Flip Point, TEIs will retain a lesser portion of the cash and the taxable income (losses) generated by the facility.

	Commercial Operation Date	Expected TEI Flip Point[1]	TEI Investment (M$)	Expected Annual PTC Generation[3] (M $)	Expected Annual Pay-go Contribution (M$)	TEI Allocation of Taxable Income (Loss) and PTCs (Pre-Flip Point)	TEI Allocation of Cash Distributions (Pre-Flip Point)
Shannon[1,2]	2015	2028	274.2	23.1	—	99.00%	64.30%
Flat Top[1,2]	2018	2028	267.2	28.3	—	99.00%	49.00%
Foard City[2,4]	2019	2029	372.7	42.3	4.5	99.00%	5.00%

1. Before the Flip Point, TEI cash distributions are based on a quarterly test measurement of cumulative generation for the project since commercial operations date. Lower production could result in a higher cash allocation to the tax equity investor or a change to the Flip Point. Figures provided are for the year ended December 31, 2019.
2. TEIs in U.S. projects generally require certain sponsor guarantees as a condition for their investment. To support the tax equity investments at Shannon, Flat Top and Foard City, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project-level representations, warranties and covenants. The Corporation believes these indemnifications cover matters that are substantially within its control, and are very unlikely to occur.
3. Based on the gross estimated LTA and the current credit of US$25/MWh generated for the period from COD to Flip Point, translated into Canadian dollars at 1.2988. PTCs generation will vary depending on actual production.
4. Average annual Pay-go Contributions estimate is based PTCs generated on gross estimated LTA for each year from COD to Flip Point, translated into Canadian dollars at 1.2988. Pay-go Contributions will vary depending on actual production in excess of 1,165 GWh per-annum, up to a cumulative maximum of US$36.5 million ($47.4 million).

Investment Tax Credit Program ("ITC")

Current United States tax law allows wind and solar facilities to receive a one-time federal tax credit, calculated on the basis of the facility's capital cost. Projects that began construction through 2019 are eligible for 30% ITC. This credit steps down to 26% for facilities that began construction in 2020, 22% in 2021 and 10% thereafter.

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

	Commercial Operation Date	Expected TEI Flip Point	TEI Investment (M$)	TEI Allocation of Taxable Income (Loss) and ITC (Pre-Flip Point)	TEI Preferred Allocation of Cash (Pre-Flip Point)
Phoebe[1,2,3]	2019	2026	244.3	99.0%	10.62% in excess of priority distribution

1. TEIs in U.S. projects generally require certain sponsor guarantees as a condition for their investment. To support the tax equity investments at Phoebe, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project-level representations, warranties and covenants. The Corporation believes these indemnifications cover matters that are substantially within its control, and are very unlikely to occur.
2. Phoebe's cash distribution amounts to the TEI are fixed and defined within the TEI partnership agreement. All amounts of distributable cash in excess of this defined threshold are distributed at the rate of 10.62% and 89.38% to the TEI and Innergex respectively.
3. TEI Allocation of Taxable Income (Loss) and ITC are 99% until February 15, 2020, down to 66.67% from February 15, 2020, to December 31, 2024, and then back to 99.0% until TEI Flip Point.

KEY PERFORMANCE INDICATORS

The Corporation measures its performance using key performance indicators ("KPIs").

Production KPIs

When evaluating its operating results, a key performance indicator for the Corporation is to compare actual electricity generation with a long-term average ("LTA"), which is determined to allow long-term forecasting of the expected power generation of each facility.

- Production in comparison with LTA in megawatt/hours ("MWh") and gigawatt/hours ("GWh")
- Production and Production Proportionate

Financial KPIs

- Revenues and Revenues Proportionate
- Adjusted EBITDA, Adjusted EBITDA Margin and Adjusted EBITDA Proportionate
- Adjusted Net Earnings (Loss)
- Free Cash Flow
- Payout Ratio

The Corporation believes that these indicators are important, as they provide management and the reader with additional information about the Corporation's production and cash generating capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. The indicators also facilitate the comparison of results over different periods.

These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

BUSINESS STRATEGY

The Corporation's fundamental goal is to create wealth by efficiently managing our high-quality renewable energy assets and successfully pursuing our growth.

We are guided by our philosophy that balances investing in people, caring for our planet and generating prosperity by sharing economic benefits with local communities and creating shareholder value.

Innergex is committed to developing, acquiring, owning and operating renewable energy facilities exclusively that generate sustainable cash flows, provide an attractive risk-adjusted return on invested capital and enable the distribution of a sustainable dividend.

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

Produce Renewable Energy

The Corporation is committed to producing energy from sustainable renewable sources exclusively, by balancing economic, social and environmental considerations. By harnessing the power of the sun's rays, the natural flow of water and the motion of the air, we work with nature to generate clean energy for a brighter future.

Optimize Operations

Innergex owns interests in 37 hydroelectric facilities drawing on 31 watersheds, 26 wind farms and 5 solar farms. The expertise and innovation developed by our skilled team in various energies and different locations can be leveraged and shared among the Corporation to maximize returns from our high-quality assets.

Maintain Diversification of Energy Sources

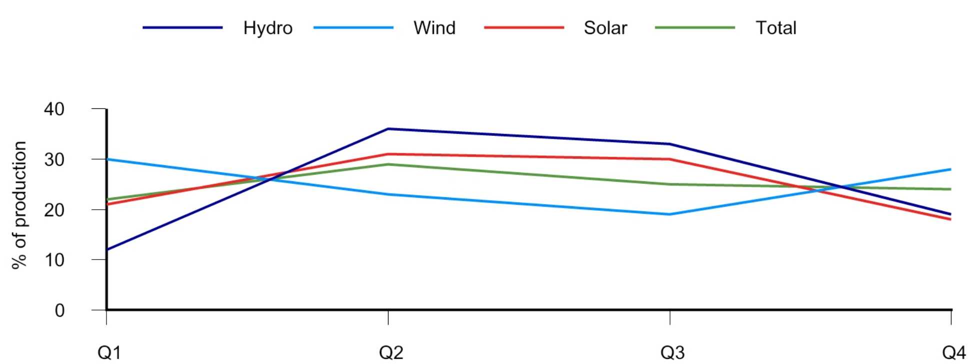
The Corporation aims to maintain a diversified portfolio of assets in terms of geography and sources of energy to alleviate any seasonal and production variations. The amount of electricity generated by the Operating Facilities is generally dependent on the availability of water flows, wind regimes and solar irradiation. Lower-than-expected resources in any given year could have an impact on the Corporation's revenues and hence on its profitability.

Fortunately, the complementary nature of hydroelectric, wind and solar energy production partially offsets any seasonal variations, as illustrated in the following table:

	Consolidated LTA and Quarterly Seasonality[1]									
In GWh and %	Q1		Q2		Q3		Q4		Total	
HYDRO	370	12%	1,065	36%	1,002	33%	581	19%	3,018	37%
WIND	1,298	30%	1,014	23%	826	19%	1,217	28%	4,355	53%
SOLAR	160	21%	242	31%	232	30%	142	18%	776	10%
Total	1,828	22%	2,321	29%	2,060	25%	1,940	24%	8,149	100%

1. The consolidated long-term average production is the annualized LTA for the facilities in operation as of February 27, 2020. The LTA is presented in accordance with revenue recognition accounting rules under IFRS and excludes production from facilities that are accounted for using the equity method. Production in comparison to the LTA is a key performance indicator for the Corporation. For more information, please refer to the "Key Performance Indicators" section.

Seasonality of Production by Energy Source



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

Grow Responsibly

The transition to a carbon-neutral economy will be led by the renewable energy sector. Innergex stands well-positioned to continue its strategic growth by further developing, acquiring, owning and operating high-quality renewable energy projects and will continue to champion the advancement of renewable energy solutions.

Nurturing relationships to develop long-term partnerships that support fruitful renewable energy projects is at the core of our business strategy and values. Our projects flourish with the support of our financial, corporate, Indigenous and municipal partners. Our values of following our passion, getting involved, driving opportunities, leading with integrity, achieving together, acting safely and generating prosperity are all ingredients of our success.

Acquisitions are another important component of the Corporation's business strategy. Gaining a foothold in new markets increases our reach, diversity and opportunities for growth. Similarly, increasing our presence in established locations allows us to consolidate our position as a renewable energy leader, such as in the Canadian market. Our focus will remain on generating energy solely from renewable sources and we will continue to explore new technologies that could bring further opportunities in electricity production and beyond, such as energy storage.

Key Growth Factors

The Corporation's future growth will be subject to the following key factors:

- The growing demand for renewable energy, as key to the energy transition to fight climate change, as supported by international agreements such as the Paris Agreement;
- Increasing awareness of the benefits of renewable energy in addressing the impacts of climate change;
- The stable and long-term government policies for the procurement of new renewable energy capacity;
- The availability of long-term renewable energy purchase contracts with highly creditworthy counterparties;
- The implementation of non-discriminatory access to transmission systems, providing independent power producers with access to certain regional electricity markets;
- Its capacity to evaluate and secure the best prospective sites for the development of new projects in cooperation with local communities;
- Its ability to adequately forecast total construction costs, expected revenues and expected expenses for each project, in a market with rapidly improving cost-competitiveness of renewable energy generation facilities;
- Its ability to make accretive acquisitions; and
- Its ability to finance its growth.

Key Geographic Markets

In Canada, in response to its commitments under the Paris Agreement, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change. Among its goals, the plan commits to phasing out coal-fired generation by 2030, and resulted in the implementation of a national price on carbon in 2019. Canada currently generates 80% of its electricity from clean, non-emitting sources and has set a goal to increase this to 90% by 2030. The Corporation continues to seek potential opportunities and participate in requests for proposals, when available, across the country. While there are no current requests for proposal (RFP) in Quebec, Ontario or British Columbia, the Corporation is well positioned to take advantage of longer term opportunities due to our operational presence and our many prospective projects.

In the United States, the Corporation increased its presence with the commissioning of the Foard City and Phoebe facilities. It continues its development with the Hillcrest and two Hawaii solar projects, while assessing potential opportunities in light of the existence of Federal Tax Credits. Throughout 2019, states continued to advance new commitments to renewable energy generation. Twenty-nine states, Washington, D.C., and three territories have now adopted a renewable portfolio standard, with nine jurisdictions including Hawaii requiring 100% clean electricity by 2050 or sooner. In addition, a growing number of cities and corporations are looking to power their operations with renewable energy exclusively through PPAs, which creates new opportunities for industry growth. Texas is the leader in installed wind energy with almost 24 GW of wind capacity currently installed and more than 6 GW under construction. The high levels of direct solar radiation in the central and western parts of Texas give the state some of the largest solar energy potential in the US and so far almost 2.3 GW of utility-scale solar have been installed with over 13 GW of growth projected by 2025. The strong project economics of wind and solar generation in the state point to sustained market momentum. In the PJM interconnection region, which covers all or part of 13 states, including Ohio and Pennsylvania, renewable energy sources have faced some headwinds as plentiful natural gas supplies drive the price of electricity down while changes to capacity market rules are under development. The outlook for renewable development in the 2020s, though, looks strong with 15.3 GW of onshore wind and 62.5 GW of solar with active filings in the interconnection queue. The Corporation continues to see excellent opportunities for growth in US markets as electricity demand rises and state governments, corporations and consumers push for increased renewable energy generation.

In 2019, the French government confirmed its target to increase the share of renewable energy in the next 10 years by setting specific targets by technology. Although France is likely to reduce the availability of its feed-in tariff contracts, it has committed to extend the RFP system for sourcing additional renewable power. In line with its strategic objectives of reaching 35 GW onshore wind capacity by 2028, RFPs are expected to call for 1.5 to 2 GW of additional projects every year. Awarded PPAs would still be offered through a government-backed entity for a long period of time (20 years).

Renewable power continues to increase in Chile. In 2019, the production of solar and wind energy reached a total of 11,186 GWh, a 22% increase from 2018, representing 14.5% of the total generated power. Meanwhile, hydroelectric facilities continue to play a significant role, in 2019 they accounted for 27% of total generation (equivalent to 20,793 GWh). Mining, which consumes about a third of Chile's overall power production, is also the industry that consumes most of the new renewable energy. Since 2014, the prices of solar energy dropped by more than 60%, prompting the mining sector and other sectors to invest in renewable energy to reduce their energy bills. The National Electric Coordinator (ISO) foresees that, in 2020, 62 new power facilities will begin operation, producing about 4,000 MW of additional power, of which 1,504 MW will come from 34 new solar facilities, 1,107 MW from 9 wind facilities and 756 MW from 10 new hydroelectric facilities. Chile has committed to generating 60% of its energy from renewable sources by 2035, and 70% by 2050, and also intends to phase out coal-fired plants.

Deliver Exceptional Results

Innergex recognizes that what we have accomplished and what is yet to come would not be possible without our highly skilled team of employees who share our mission, vision, values and key principles.

Their collective knowledge, talent, abilities, experience and sound judgment have always been key to our long-term success. Our management team has a proven track record of delivering projects on-time and on-budget. As of December 31, 2019, the Corporation employs a team of 327 highly talented individuals to which are added 83 people working for our joint venture partner Energía Llaima in Chile.

Furthermore, we have nurtured a pool of specialized partners we can rely on to provide services outside our realm of expertise when necessary, from engineering firms to environmental monitoring professionals.

SELECTED ANNUAL INFORMATION

	Year ended December 31[1]		
	2019	2018	2017
PRODUCTION			
Production (MWh)	6,509,622	5,086,497	4,394,210
LTA (MWh)	6,770,170	5,283,616	4,763,836
Production as percentage of LTA	96%	96%	92%
STATEMENT OF EARNINGS			
Revenues	557,042	481,418	400,263
Adjusted EBITDA[2]	409,175	352,179	298,728
Adjusted EBITDA Margin[2]	73.5%	73.2%	74.6%
Net (Loss) Earnings From Continuing Operations	(53,026)	26,215	19,136
Adjusted Net (Loss) Earnings From Continuing Operations[2]	(25,817)	13,963	15,662
Net (Loss) Earnings	(31,211)	25,718	19,136
Net (Loss) Earnings From Continuing Operation Attributable to Owners of the Parent	(47,723)	31,825	29,475
($ per common share - basic)	(0.40)	0.20	0.22
($ per common share - diluted)	(0.40)	0.20	0.22
Weighted average number of common shares (in 000s)	134,658	130,030	108,427
PROPORTIONATE			
Production Proportionate (MWh)[2]	8,021,758	6,361,733	4,497,943
Revenues Proportionate[2]	660,941	564,686	411,468
Adjusted EBITDA Proportionate[2]	516,819	428,684	308,343
STATEMENT OF FINANCIAL POSITION			
Total Assets	6,372,104	6,516,158	4,190,456
Long-Term Loans and Borrowings, Including the Current Portion	4,691,669	4,708,397	3,153,262
Total Non-Current Liabilities	5,115,425	4,932,829	3,490,350
Total Equity	615,326	942,037	453,262
DIVIDENDS			
Declared per Series A Preferred Share	0.902	0.902	0.902
Declared per Series C Preferred Share	1.4375	1.4375	1.4375
Declared per common share	0.70	0.68	0.66
PAYOUT RATIO			
Dividends declared on common shares	95,046	90,215	71,621
Free Cash Flow[2,3]	93,311	105,124	87,207
Payout Ratio[2,3]	102%	86%	82%
Adjusted Payout Ratio[2,3]	88%	66%	64%

1. Results from continuing operations unless otherwise indicated.
2. Adjusted EBITDA, Adjusted EBITDA Margin, Innergex's share of Adjusted EBITDA of Joint Ventures and Associates, Adjusted EBITDA Proportionate, Adjusted Net Earnings, Free Cash Flow and Payout ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
3. For more information on the calculation and explanation of the Corporation's Free Cash Flow and Payout Ratio, please refer to the "Free Cash Flow and Payout Ratio" section.

Financial year 2019

For the year ended December 31, 2019, the increase in Production (MWh), revenues, Adjusted EBITDA and Adjusted EBITDA Proportionate from continuing operations are attributable mostly to the contribution of the 62% interest in the Cartier Wind Farms acquired in October 2018 and to the contribution of the facilities commissioned in 2019.

The Corporation recorded $53.0 million in net loss from continuing operations compared with net earnings of $26.2 million in 2018, mainly due to higher deferred income tax expense related to tax attributes and PTCs allocated to tax equity investors, higher unrealized net loss on financial instruments, finance costs and depreciation and amortization. Those unfavorable elements were partly offset by other revenues generated by tax attributes and PTCs from the commissioning of Foard and Phoebe, and by higher Adjusted EBITDA mainly related to the contribution of the Cartier Wind Farms and the facilities commissioned in 2019.

The decrease in total assets is due mainly to the sale of HS Orka that was partially offset by the additional fixed assets of the Foard City wind facility and Phoebe solar facility that were both commissioned in 2019, and the application of IFRS 16.

The increase in long-term loans and borrowings results mainly from the commissioning of the Phoebe and Foard City facilities.

The equity attributable to owners increased due mainly to the conversion of the convertible debentures and the earnings of 2019 net of the dividends declared.

The decrease in Free Cash Flow is due mainly to greater scheduled debt principal payments and a decrease in cash flows from operating activities before changes in non-cash working capital items, including the contribution from the discontinued operations, partly offset by a decrease in the Free Cash Flow attributed to non-controlling interests mainly related to the disposal of HS Orka hf, as well as below-average water flows in British Columbia affecting certain facilities containing non-controlling interests. The Corporation's payout ratio was 102% for the year ended December 31, 2019.

Financial year 2018

For the year ended December 31, 2018, the increase in Production (MWh), revenues, Adjusted EBITDA and Adjusted EBITDA Proportionate from continuing operations are attributable mostly to the contribution of the facilities acquired in 2018.

The Corporation recorded $26.2 million in net earnings from continuing operations compared with 19.1 million in 2017, mainly due to higher Adjusted EBITDA and a positive change in the share of net earnings of joint ventures and associates, partly offset by higher finance costs and depreciation and amortization.

The increase in total assets is due mainly to the acquisition of Alterra, the 62% acquired interest in the Cartier Wind Farms, the 50% ownership investment in Energía Llaima and the acquisition and advancement of the Phoebe solar project.

The increase in long-term loans and borrowings results mainly from the non-recourse financing of $570.4 million with regards to four operating wind farms ("Cartier Credit Facility"). The proceeds from the Cartier Credit Facility were used to repay the $400 million one-year credit facility contracted to pay for a portion of the acquisition of the Cartier Wind Farms and Operating Entities and the existing credit facilities of the L'Anse-à-Valleau, Carleton and Montagne Sèche facilities as well as to deleverage the corporate credit facilities with the remaining $69 million. The increase in long-term loans and borrowings is also attributable to the $150 million subordinated unsecured five-year term loan obtained in February 2018 to finance the cash portion of the Alterra acquisition, to $131 million (US$100 million) drawn on the revolving credit facilities used for the investment in Energía Llaima and the Duqueco acquisition in Chile, to the addition of the long-term debt acquired with Alterra, to the construction loan for the Phoebe project and to drawings made on the corporate revolving credit facilities for the construction of the Foard City wind project. The increase was partly offset by repayments made on the corporate revolving credit facilities stemming from proceeds of the $150 million debentures offering and by scheduled repayments of project-level debts.

The equity attributable to owners increased due mainly to the issuance of 24,327,225 shares on February 6, 2018, in connection with the Alterra acquisition, partly offset by a change in the fair value of hedging instruments in other comprehensive income.

The increase in Free Cash Flow is due mainly to higher cash flows from operating activities before changes in non-cash working capital items, partly offset by greater scheduled debt principal payments, higher Free Cash Flow attributed to non-controlling interests and higher maintenance capital expenditures net of proceeds from disposals. The Corporation's payout ratio was 86% for the year ended December 31, 2018.

2019 HIGHLIGHTS

Corporate Development

Divestment of HS Orka

- On May 23, 2019, Innergex announced completion of the sale of its wholly owned subsidiary Magma Sweden, which owns an equity interest of approximately 53.9% in HS Orka for US$297.9 million ($401.5 million) after adjustments to Jarðvarmi slhf, which exercised its right of first refusal.
- The net proceeds were used to reimburse the $228 million one-year credit facility contracted on October 24, 2018 at the time of the acquisition of the remaining interest in the Cartier Wind Farms and Operating Entities and the utilized portion of the additional borrowing capacity of $100 million that was obtained on April 23, 2019. The proceeds were also used to deleverage corporate facilities.

Solar Development in the United States

- During the year, 125 MW of solar panels were acquired qualifying approximately 650 MW of future solar projects.

Debenture Redemption

- On September 5, 2019, the Corporation issued a notice of redemption and expiry of conversion privilege in respect of the aggregate outstanding principal amount of $100 million of the 4.25% convertible unsecured subordinated debentures that were due to mature on August 31, 2020 (the "4.25% Convertible Debentures"). Of that principal amount, $86.7 million was converted at the holders' request into a total of 5,776,795 Innergex common shares at a conversion price of $15 per share. The remaining $13.3 million was redeemed on October 8, 2019 at a price of $1,000 per debenture, plus accrued and unpaid interest up to, but excluding, October 8, 2019, and was financed with drawings under the Corporation's revolving term credit facility. The debentures were delisted from the TSX on October 8, 2019.

Debenture Offering

- On September 30, 2019, the Corporation completed its bought deal offering of convertible unsecured subordinated debentures (the "Debentures") for an aggregate principal amount of $125 million at a price of $1,000 per $1,000 principal amount of Debenture, bearing interest at a rate of 4.65% per annum, payable semi-annually, in arrears on October 31 and April 30 each year, commencing on April 30, 2020 (the "4.65% Convertible Debentures").
- The net proceeds of the 4.65% Convertible Debentures offering were used to initially prepay indebtedness under the Corporation's revolving term credit facility, which was then available to be drawn, as required, to finance the redemption of all outstanding 4.25% Convertible Debentures. The remaining net proceeds were available to be drawn, as required, to fund development projects and other growth opportunities or for general corporate purposes.
- On October 2, 2019, the Corporation announced that it has issued an additional $18.75 million aggregate principal amount of 4.65% Convertible Debentures following the exercise in full of the over-allotment option granted (the "Over-Allotment Option") to the underwriters in connection with the 4.65% Convertible Debentures offering.
- After taking into account the Over-Allotment Option, the Corporation raised aggregate gross proceeds of $143.75 million under the offering, of which $13.3 million was used to redeem the 4.25% Convertible Debentures.

Development Activities

	Location	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1] (GWh)	PPA term (years)
HYDRO (Chile)					
Frontera	Biobío	109.0	2022	464.0	- [2]
El Canelo	Cordillera	16.0	2022	90.0	- [2]
SOLAR (United States)					
Hale Kuawehi	Hawaii	30.0 [3]	2022	87.4	25
Paeahu	Hawaii	15.0 [3]	2022	41.2	25
WIND (France)					
Yonne II	France	6.9	2020	11.0	20

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary. These estimates are up-to-date as at the date of this MD&A.
2. Power to be sold on the open market or through PPAs yet to be signed.
3. Solar project with a battery storage capacity of 120 MWh for Hale Kuawehi and 60 MWh for Paeahu.

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

Frontera

- The financing process is progressing.
- The construction contract is progressing.
- During the next months, depending of the results of the financing process, the Corporation will make a final decision on the project's fate.

El Canelo

- The project is being redesigned to address various issues, which has delayed the issuance of permits.
- The project is at a critical point where a decision on its future could be made in the coming months.

Hale Kuawehi

- The Public Utilities Commission ("PUC") approved the PPA.
- Environmental and technical studies are ongoing, as are other permitting-related activities.
- 30% design engineering is underway and will be completed in the first quarter of 2020.

Paeahu

- The PUC's PPA review process is ongoing. A contested case hearing took place in the fourth quarter of 2019 to address concerns from an opposition group that consists of neighboring residents. The PUC is expected to make a decision in the first quarter of 2020.
- Environmental and technical studies are ongoing as are other permitting-related activities. The Special Use Permit application will be filed in the second quarter of 2020 and will likely face opposition from the same group.

Yonne II

The Yonne II project is an extension of the Yonne wind facility located in Bourgogne-Franche-Comté, France.

- Innergex owns 69.55% of the project.
- The project is comprised of 3 turbines of a 2.3 MW capacity each.
- All authorizations have been granted, are free from recourse, and a fixed price 20-year PPA has been signed with EDF.
- Financing is expected to close in Q1 2020 and construction is scheduled to start in Q2 2020.

Construction Activities

	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project cost	Expected first 5-year average	
						Estimated[1] ($M)	Revenues[1] ($M)	Adjusted EBITDA[1,2] ($M)
SOLAR (United States)								
Hillcrest	100.0	200.0	2020	410.0	15	362.6 [4]	22.1 [4]	14.5 [4]
HYDRO (Quebec)								
Innavik	50.0	7.5	2022	54.7	40	125.0 [3]	11.0 [3]	8.9 [3]
Total		207.5		464.7		487.6	33.1	23.4

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary. These estimates are up-to-date as at the date of this MD&A.
2. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
3. Corresponding to 100% of this facility.
4. Total Estimated Project Cost at US$279.2 million, Expected Revenues at US$17.0 million and Expected Adjusted EBITDA at US$11.2 million translated at a rate of 1.2988.

Hillcrest

- Two limited notice to proceed contracts have been executed with an engineering, procurement and construction firm (EPC), for the execution of racking and inverter supply agreements, project design and on-site pile testing. The execution of the EPC agreement should take place in Q1-2020.
- On November 28, 2019, the Corporation announced that a long-term PPA was signed with an investment grade rated US corporation. Sales under the PPA will start upon the facility reaching commercial operation, which is expected in 2020.
- Term sheet negotiations are underway with a tax equity investor and a group of lenders, who are performing their due diligence in parallel. Financial close is targeted for Q2 2020.
- Construction mobilization commenced on January 27, 2020.

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

Innavik

- A 40-year PPA was signed with Hydro-Québec Distribution on May 27, 2019, with production expected to begin in the fourth quarter of 2022. The PPA was approved by the Régie de l'énergie du Québec in December 2019.
- The first construction equipment was delivered in September and construction is planned to start in Q2 2020.
- The on-site workers' camp is ready for the start of construction.

Commissioning Activities

	Ownership %	Gross installed capacity (MW)	COD	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project cost	Expected first 5-year average	
						Estimated[1] ($M)	Revenues[1] ($M)	Adjusted EBITDA[1,2] ($M)
WIND (United States)								
Foard City	100.0	350.3	2019	1,303.3	12 [4]	524.2 [3]	25.6 [3]	11.8 [3]
SOLAR (United States)								
Phoebe	100.0	250.0	2019	713.7	12 [6]	515.6 [5]	34.9 [5]	28.0 [5]
Total		600.3		2,017.0		1,039.8	60.5	39.8

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary. These estimates are up-to-date as at the date of this MD&A.
2. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the “Non-IFRS Measures” section of this MD&A for more information.
3. Total Estimated Project Cost at US$403.6 million, Expected Revenues at US$19.7 million and Expected Adjusted EBITDA at US$9.1 million translated at a rate of 1.2988.
4. PPA for 300 MW.
5. Total Estimated Project Cost at US$397.0 million, Expected Revenues at US$23.6 million and Expected Adjusted EBITDA at US$18.3 million translated at a rate of 1.2988.
6. Power hedge contract accounted for as a financial derivative at fair value through earnings (loss).

Foard City

- On September 27, 2019, the Corporation began commercial operation of the 350.3 MW Foard City wind farm, a project consisting of 139 GE wind turbines spread over 31,449 acres in Foard County, Texas. The wind farm benefits from a 12-year power purchase agreement with Vistra Energy for 300 MW of its installed capacity. The remainder of the project's output will receive a merchant market price.
- Concurrent with the commissioning, the US$236.4 million ($312.2 million) tax equity bridge loan was reimbursed with the proceeds from the tax equity investor's contribution of US$282.3 million ($372.7 million). The construction loan amounting to US$23.4 million ($30.9 million) was converted into a 7-year term loan facility.
- The project will benefit from 100% of the U.S. PTCs, representing US$25.00 per MWh of electricity produced for the first 10 years of operations. This amounts to an after-tax benefit of approximately US$32.6 million per year ($42.3 million) adjusted by inflation annually and, coupled with other tax attributes, will support the US$282.3 million ($372.7 million) tax equity investment.
- Foard City is expected to produce a gross estimated long-term average of 1,303 GWh, annual projected revenues of approximately US$19.7 million ($25.6 million) and annual projected Adjusted EBITDA of approximately US$9.1 million ($11.8 million), excluding Pay-go Contributions.
- Final construction costs amounted to US$404.6 million ($525.6 million).

Phoebe

- On November 19, 2019, the Corporation announced the full commissioning of the 250 MW Phoebe solar farm, a project consisting of 768,000 First Solar Series 6 thin film photovoltaic solar panels sited on approximately 3,500 acres of land in Winkler County, Texas. The solar farm benefits from a fixed price 12-year power hedge agreement for 89% of the energy produced. The remainder of the project's output will receive a merchant market price.
- Concurrent with the commissioning, the US$176.2 million ($232.6 million) tax equity bridge loan was reimbursed with the proceeds from the tax equity investor's contribution of US$184.6 million ($244.3 million). A portion of the construction loan facility of US$115.9 million ($152.9 million) was converted into a 7-year term loan facility.
- The project is eligible to receive a federal Investment Tax Credit (ITC) sized to approximately 30% of the project's costs, 99% of which was allocated to the project's tax equity partner during the year ended December 31, 2019.
- Previous annual gross estimated LTA of 738.0 GWh, annual projected revenues of approximately US$25.6 million ($33.2 million) and annual projected Adjusted EBITDA of approximately US$19.6 million ($25.5 million) were reviewed to take into consideration various production factors, including the fact that, from October 1, 2019 onwards, the Phoebe revenues are recognized on a merchant basis (see "Power hedge" below). Annual gross estimated LTA now stands at 713.7 GWh, while projected revenues and Adjusted EBITDA stand at US$26.9 million ($34.9 million) and US$21.6 million ($28.0 million) on average for the first 5 years of operations, respectively, subject to the volatility of the local nodal prices.
- Final construction costs amounted to US$397.3 million ($516.0 million).

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

Power hedge

Through its acquisition of the Phoebe solar project on July 2, 2018, Innergex acquired a 12-year power hedge, effective from July 1, 2019 to June 30, 2031. On the acquisition date, the power hedge was measured at its fair value of US$16.1 million ($21.2 million). As of that date, it was designated for hedge accounting purposes. Subsequent changes in the fair value of the power hedge were mainly recognized through other comprehensive income. To determine the fair value of the Phoebe power hedge and support the hedge effectiveness testing for hedge accounting purposes, forward prices of the ERCOT South Hub and the Phoebe Node were required, however quoted forward market prices at the hub were limited and forward prices unavailable at the node. The price differential risk between the hub and the node (or “basis differential risk”) had been assumed negligible for this purpose. The Phoebe facility started delivering energy at the node in June 2019 and commenced delivering energy under the power hedge on July 1, 2019. While the basis differential behaved relatively as expected during the first months of production, evidence that changes in the Phoebe Node prices were not closely aligned with changes in the ERCOT South Hub prices materialized in October 2019. In light of this new information, Management revised, during the fourth quarter of 2019, its methodology to derive forward node prices in order to more accurately reflect the basis differential risk, which resulted in the Phoebe power hedge no longer meeting the hedge effectiveness criteria.

Since the forecasted transactions are still expected to occur, the cumulative changes in fair value totaling $36.5 million as at December 31, 2019, recognized in accumulated other comprehensive income at the hedge relationship cessation date will remain and be reclassified to revenue over the remaining term of the power hedge. Subsequent changes in the fair value of the derivative instrument will be recognized in the consolidated statement of earnings, as unrealized net loss (gain) in financial instruments. From October 1, 2019 onwards, settlements under the power hedge therefore no longer affect revenue. As such, revenues of the Phoebe solar project are recognized on a merchant basis, subject to the volatility of the local nodal prices.

Basis hedge

As described above, the basis differential risk between the ERCOT South Hub and the Phoebe Node prices was initially assumed negligible. However, in order to protect the project's returns in the event of a change in the expected price dynamics at the hub and the node, and in light of the existing transmission congestion prevailing in Texas broadening the basis differential risk at numerous locations, on August 2, 2019, the Corporation entered into a 2-year basis hedge, effective from November 1, 2019 to December 31, 2021.

Under the basis hedge, Innergex swaps the ERCOT South Hub and the Phoebe Node prices at a contractual hourly quantity of 100 MW, for 16 hours daily. As supported by the studies carried out by Innergex's external consultants prior to the transaction being executed, the basis hedge was designed to protect the basis risk associated with the power hedge during the daily generation period, while the exposure outside of such generation period was expected to be limited.

However, for the period from November 1, 2019 to December 31, 2019, contrary to the initial expectation, the project has been exposed to large unfavourable basis differentials outside of the generation hours, which contributed to a realized loss of $11.7 million for the period recorded in the project’s tracking account[1] and in reduction of the derivative financial liability as at December 31, 2019.

The basis hedge is accounted for at fair value, with subsequent changes being recognized in the consolidated statement of earnings, as unrealized net loss (gain) on derivative financial instruments. The change in fair value recognized as an unrealized net loss on derivative financial instruments amounted to $48.0 million for the year ended December 31, 2019.

[1] Renewable energy projects selling energy under a power/basis hedge structure are exposed to mismatch risks mainly driven by: (1) the risk of a shortfall in the actual energy produced in comparison to the contractual hourly quantity under the hedges; and (2) a price differential risk between hub, node, and fixed contractual prices per MW of contracted energy. To cover such temporary unfavourable mismatch, the counterparty provides the project with a tracking account; a working capital loan that is repaid with subsequent favourable mismatch.

Operating Activities

Glen Miller

On June 15, 2019, a flood incident occurred at the Glen Miller hydro facility in Ontario. Operations were halted for a few weeks and resumed mid-July. A $1.5 million provision was recorded in other expenses for potential cash outflows related to this event, including contractual penalties.

OPERATING RESULTS

Electricity Production

The Corporation's operating results for the three-month period ended December 31, 2019 are compared with the operating results for the same period in 2018.

	Three months ended December 31					
	2019			2018		
Energy Segment	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	162,604	181,486	90%	172,318	181,486	95%
Ontario	21,937	21,212	103%	22,625	21,212	107%
British Columbia	235,450	372,987	63%	333,194	372,988	89%
United States	2,212	5,223	42%	1,897	5,223	36%
Subtotal	422,203	580,908	73%	530,034	580,909	91%
WIND						
Quebec[2]	658,213	671,037	98%	659,210	595,124	111%
France	241,589	214,319	113%	199,116	214,319	93%
United States[3]	338,353	331,840	102%	—	—	—%
Subtotal	1,238,155	1,217,196	102%	858,326	809,443	106%
SOLAR						
Ontario	5,179	5,621	92%	4,849	5,661	86%
United States[4]	128,266	131,357	98%	2,857	3,732	77%
Subtotal	133,445	136,978	97%	7,706	9,393	82%
Total	1,793,803	1,935,082	93%	1,396,066	1,399,745	100%
GEOTHERMAL[5]						
Iceland	—	—	—%	351,642	319,740	110%

1. Some facilities are treated as joint ventures and associates and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for consistency, their electricity production figures have been excluded from the production table.
2. Production and LTA reflects the 62% acquired interest in the Cartier Wind Farms on October 24, 2018. LTAs were revised at the acquisition.
3. Foard City was commissioned on September 27, 2019.
4. The Phoebe solar project was commissioned on November 19, 2019. Before that date, blocks of modules gradually produced energy. LTAs during the gradual production period were equivalent to production; since commissioning, regular LTAs are used.
5. Production and LTA were nil for the period in 2019 as opposed to a complete period in 2018.

Overall, the **hydroelectric** facilities produced 73% of their LTA due mostly to:
- below-average water flows at the British Columbia facilities; and
- below-average water flows at some Quebec facilities.

Overall, the **wind** farms produced 102% of their LTA due to:
- above-average wind regimes in France; and
- above-average wind regimes in the United States.

These items were partly offset by:
- below-average wind regimes in Quebec.

Overall, the **solar** farms produced 97% of their LTA mostly due to:
- below-average solar irradiation in the United States.

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

Production for the three-month period ended December 31, 2019 was 1,793,803 MWh compared with 1,396,066 MWh for the same period last year. The 28% increase is due mainly to:

- the contribution of the Foard City wind farm commissioned on September 27, 2019;
- the energy produced and sold by the Phoebe solar facility during production ramp-up and the subsequent completion of commissioning activities on November 19, 2019;
- higher production in France.

These items were partly offset by:

- below-average water flows at the British Columbia facilities.

The Corporation's operating results for the twelve-month period ended December 31, 2019 are compared with the operating results for the same period in 2018.

	Twelve months ended December 31					
	2019			2018		
Energy Segment	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	664,458	699,930	95%	664,640	699,930	95%
Ontario	67,708	74,544	91%	73,228	74,544	98%
British Columbia	1,874,094	2,195,892	85%	2,042,452	2,195,892	93%
United States	37,702	46,800	81%	44,793	46,800	96%
Subtotal	2,643,962	3,017,166	88%	2,825,113	3,017,166	94%
WIND						
Quebec[2]	2,436,638	2,311,600	105%	1,539,420	1,471,005	105%
France	724,267	739,693	98%	660,675	734,752	90%
United States[3]	381,684	375,171	102%	—	—	—%
Subtotal	3,542,589	3,426,464	103%	2,200,095	2,205,757	100%
SOLAR						
Ontario	39,387	37,102	106%	39,263	37,363	105%
United States[4]	283,684	289,438	98%	22,026	23,330	94%
Subtotal	323,071	326,540	99%	61,289	60,693	101%
Total	6,509,622	6,770,170	96%	5,086,497	5,283,616	96%
GEOTHERMAL[5]						
Iceland	545,424	505,395	108%	1,196,939	1,154,348	104%

1. Some facilities are treated as joint ventures and associates and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for consistency, their electricity production figures have been excluded from the production table.
2. Production and LTA reflect the 62% acquired interest in the Cartier Wind Farms on October 24, 2018. LTAs were revised at the acquisition.
3. Foard City wind farm's production and LTA for the period of September 27, 2019 to December 31, 2019.
4. The Phoebe solar project was commissioned on November 19, 2019. Before that date, blocks of modules gradually produced energy. LTAs during the gradual production period were equivalent to production; since commissioning, regular LTAs are used.
5. Production and LTA for the period from January 1, 2019, to May 23, 2019 as opposed to a period from February 6 to December 31, 2018.

Overall, the **hydroelectric** facilities produced 88% of their LTA due mostly to:

- below-average water flows at most British Columbia facilities; and
- below-average water flows at some Quebec facilities.

Overall, the **wind** farms produced 103% of their LTA due to:

- above-average wind regimes in Quebec; and
- above-average wind regimes in the United States.

These items were partly offset by:

- below-average wind regimes in France in the three first quarters that were partially offset by above-average wind regimes in the fourth quarter.

Overall, the **solar** farms produced 99% of their LTA due mostly to:

- below-average solar irradiation in the United States.

Production for the twelve-month period ended December 31, 2019 was 6,509,622 MWh compared with 5,086,497 MWh for the same period last year. The 28% increase is due mainly to:

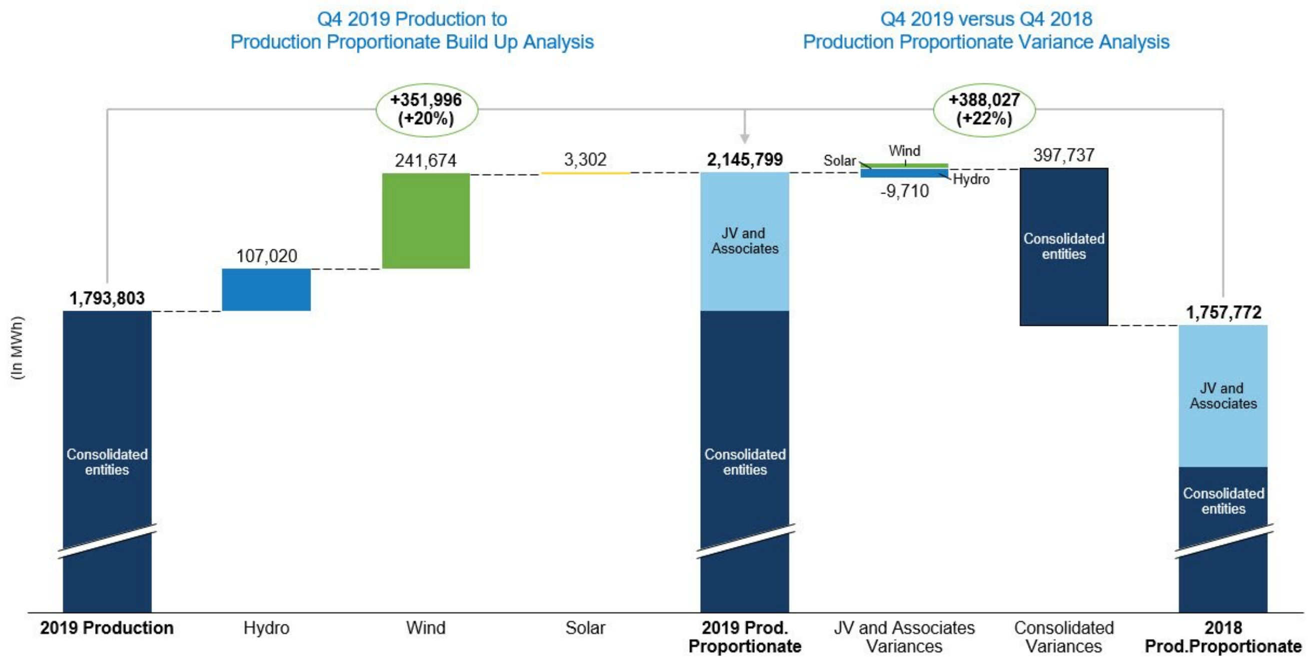
- the contribution of the 62% interest in the Cartier Wind Farms, acquired in 2018;

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

- the contribution of the Foard City wind farm, commissioned on September 27, 2019;
- the energy produced and sold by the Phoebe solar facility during production ramp-up and the subsequent completion of commissioning activities on November 19, 2019; and
- improved wind regimes in France.

These items were partly offset by:
- below-average water flows in most of British Columbia facilities.

Production Proportionate[1]



1. Production Proportionate is a "Key performance indicator" for the Corporation, which cannot be reconciled with an IFRS measure and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the three-month period ended on December 31, 2019, compared with the same period last year

Production Proportionate of the joint ventures' and associates' **hydroelectric facilities** was 107,020 MWh (89% of their LTA) in the fourth quarter of 2019, compared with 131,567 MWh (110% of their LTA) for the same quarter last year, a 19% decrease due mainly to:
- lower contribution from the Chile facilities due to below-average water flows; and
- lower contribution from the Ontario facility due to below-average water flows.

Production Proportionate of the joint ventures' and associates' **wind farms** was 241,674 MWh (99% of their LTA) in the fourth quarter of 2019 compared with 226,936 MWh (93% of their LTA) for the same period last year, a 6% increase due mostly to:
- higher contribution of the Shannon and Flat Top facilities in Texas; and
- higher contribution of the Dokie facility in British Columbia.

Production Proportionate of the joint ventures' and associates' **solar farm** was 3,302 MWh (90% of its LTA) in the fourth quarter of 2019 compared with 3,203 MWh (87% of its LTA) for the same period last year.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

Production Proportionate of the joint ventures' and associates' **hydroelectric facilities** was 599,527 MWh (98% of their LTA) for the twelve-month period ended on December 31, 2019, compared with 539,735 MWh (99% of their LTA) for the same period last year, an 11% increase due mainly to:
- the investment in Energía Llaima in July 2018; and
- higher contribution from the British Columbia facilities.

Production Proportionate of the joint ventures' and associates' **wind farms** was 899,509 MWh (98% of their LTA) for the twelve-month period ended on December 31, 2019, compared with 729,002 MWh (95% of their LTA) for the same period last year, a 23% increase due mainly to:
- the contribution of the Flat Top wind farm, commissioned on March 23, 2018; and

- the contribution of the Alterra acquisition, achieved on February 6, 2018.

Production Proportionate of the joint ventures' and associates' **solar farm** was 13,100 MWh (91% of its LTA) for the twelve-month period ended on December 31, 2019 compared with 6,499 MWh (90% of its LTA) for the same period last year, a 102% increase due to:
- the addition of the Pampa Elvira solar facility, which was part of the investment in Energía Llaima in July 2018.

Financial Results

	Three months ended December 31[1]				Year ended December 31[1]			
	2019	2018	Change		2019	2018	Change	
Revenues	143,116	138,252	4,864	4 %	557,042	481,418	75,624	16 %
Operating expenses	26,308	23,080	3,228	14 %	98,455	84,724	13,731	16 %
General and administrative expenses	11,235	7,317	3,918	54 %	36,507	27,796	8,711	31 %
Prospective project expenses	2,240	4,585	(2,345)	(51)%	12,905	16,719	(3,814)	(23)%
Adjusted EBITDA[2]	103,333	103,270	63	— %	409,175	352,179	56,996	16 %
Adjusted EBITDA margin[2]	72.2%	74.7%			73.5%	73.2%		
Finance costs	61,062	55,020	6,042	11 %	231,766	195,834	35,932	18 %
Other net (revenues) expenses	(102,004)	6,864	(108,868)	(1,586)%	(104,643)	12,183	(116,826)	(959)%
Depreciation and amortization	53,021	42,285	10,736	25 %	194,579	151,256	43,323	29 %
Impairment of project development costs	8,184	—	8,184	— %	8,184	—	8,184	— %
Share of earnings of joint ventures and associates[3]	(27,276)	(37,320)	10,044	(27)%	(36,469)	(47,596)	11,127	(23)%
Unrealized net loss (gain) on financial instruments	40,708	(9,061)	49,769	(549)%	49,933	(12,958)	62,891	(485)%
Income tax expenses	117,687	26,666	91,021	341 %	118,851	27,245	91,606	336 %
Net (loss) earnings from continuing operations	(48,049)	18,816	(66,865)	(355)%	(53,026)	26,215	(79,241)	(302)%
Net earnings (loss) from discontinued operations	644	(4,575)	5,219	(114)%	21,815	(497)	22,312	(4,489)%
Net (loss) earnings	(47,405)	14,241	(61,646)	(433)%	(31,211)	25,718	(56,929)	(221)%
(Net loss) earnings attributable to:								
Owners of the parent	(46,158)	13,690	(59,848)	(437)%	(28,041)	31,140	(59,181)	(190)%
Non-controlling interests	(1,247)	551	(1,798)	(326)%	(3,170)	(5,422)	2,252	(42)%
	(47,405)	14,241	(61,646)	(433)%	(31,211)	25,718	(56,929)	(221)%
Basic and diluted net (loss) earnings per share from continuing operations attributable to owners ($)	(0.35)	0.11			(0.40)	0.20		
Basic and diluted net (loss) earnings per share attributable to owners ($)	(0.34)	0.11			(0.25)	0.19		

1. Results from continuing operations unless otherwise indicated.
2. Adjusted EBITDA and Adjusted EBITDA Margin are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
3. Some facilities are treated as joint ventures and associates and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues.

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

Revenues

Up 4% to $143.1 million for the three-month period ended December 31, 2019
Up 16% to $557.0 million for the twelve-month period ended December 31, 2019

	Three months ended December 31			Twelve months ended December 31		
Energy Segment	2019	2018	Change	2019	2018	Change
Hydro	39,949	53,348	(13,399)	218,918	238,724	(19,806)
Wind	92,927	82,510	10,417	304,724	223,579	81,145
Solar	10,240	2,394	7,846	33,400	19,115	14,285
Revenues	143,116	138,252	4,864	557,042	481,418	75,624

For the three-month period ended on December 31, 2019, compared with the same period last year

The decrease in revenues from the **hydroelectric** power generation segment is mainly due to:
- lower production at the British Columbia facilities; and
- lower average selling price and lower production at some Quebec facilities.

The increase in revenues from the **wind** power generation segment is mainly due to:
- the commissioning of the Foard City wind farm in Texas on September 27, 2019; and
- higher revenues at the France and Quebec wind facilities due to higher production.

These items were partly offset by:
- lower revenues at the Mesgi'g Ugju's'n facility due to lower production.

The increase in revenues from the **solar** power generation segment is almost exclusively due to:
- the energy produced and sold by the Phoebe solar facility during production ramp-up and the subsequent completion of commissioning activities on November 19, 2019.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

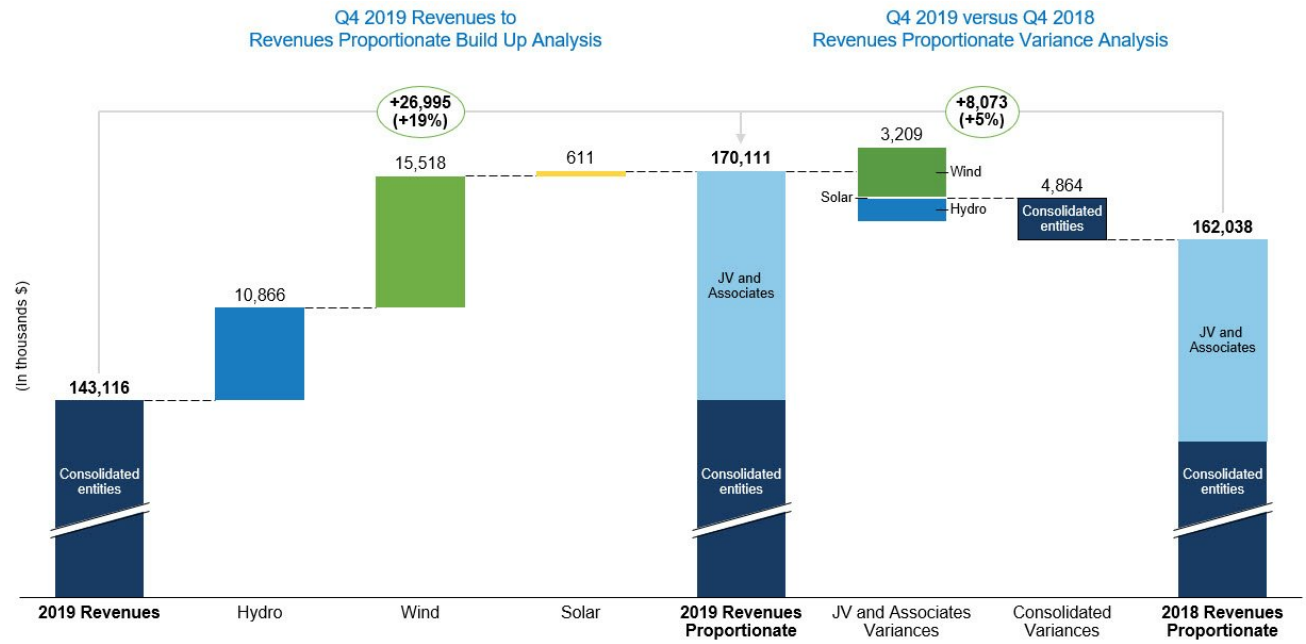
The decrease in revenues from the **hydroelectric** power generation segment is mainly due to:
- lower revenues in British Columbia attributable to a net unfavourable impact of lower production over higher average selling prices at some facilities; and
- lower revenues in Quebec from lower average selling prices at some facilities.

The increase in revenues from the **wind** power generation segment is mainly due to:
- the 62% interest in the Cartier Wind Farms acquired in October 2018;
- higher revenues at the France facilities due to higher production; and
- the contribution of the Foard City wind farm since its commissioning on September 27, 2019.

The increase in revenues from the **solar** power generation segment is almost exclusively due to:
- the energy produced and sold by the Phoebe solar facility during production ramp-up and the subsequent completion of commissioning activities on November 19, 2019.

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

Revenues Proportionate[1]



1. Revenues Proportionate is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the three-month period ended on December 31, 2019, compared with the same period last year

Joint ventures' and associates' **hydroelectric facilities** contributed $10.9 million to Revenues Proportionate in the fourth quarter of 2019, compared with a contribution of $13.6 million for the same quarter last year, a 20% decrease due mostly to:

- lower revenues from Chile facilities mostly due to lower production.

Joint ventures' and associates' **wind farms** contributed $15.5 million to Revenues Proportionate in the fourth quarter of 2019, compared with $9.7 million for the same quarter last year, a 59% increase mainly due to:

- higher contribution from the Shannon and Flat Top wind farms in Texas due to a combination of favourable nodal prices, in part arising from an annual adjustment, and production; and
- higher production at the Dokie facility in British Columbia.

Joint ventures' and associates' **solar farm** contributed $0.6 million to revenues proportionate in the fourth quarter of 2019, compared with $0.5 million for the same quarter last year.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

Joint ventures' and associates' **hydroelectric facilities** contributed $64.8 million to Revenues Proportionate for the twelve-month period ended on December 31, 2019, compared with $53.8 million for the same period last year, a 20% increase due mostly to:

- the investment in Energía Llaima in July 2018; and
- higher revenues from British Columbia facilities due to higher production from their favourable location combined with the effect of higher selling prices.

Joint ventures' and associates' **wind farms** contributed $37.0 million to Revenues Proportionate for the twelve-month period ended on December 31, 2019, compared with $28.6 million for the same period last year, a 30% increase mainly due to:

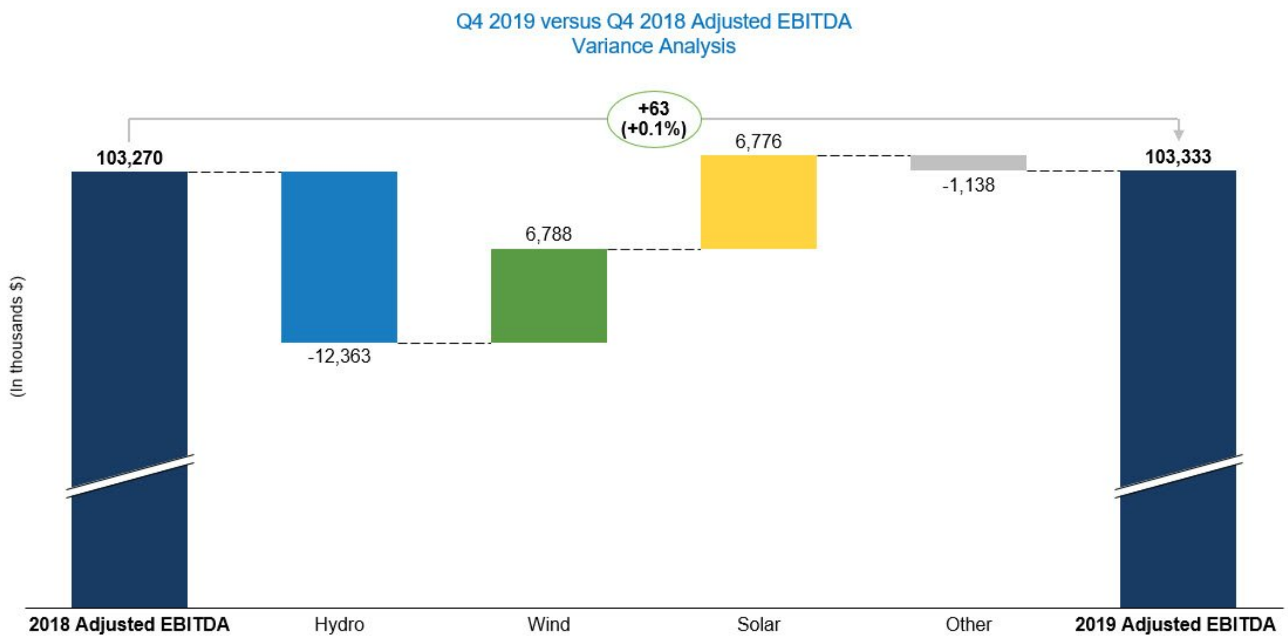
- higher production at the Flat Top wind farm commissioned on March 23, 2018;
- higher average selling price at the Shannon and Flat Top facilities; and
- the contribution of the Alterra acquisition achieved on February 6, 2018.

Joint ventures' and associates' **solar farm** contributed $2.1 million to Revenues Proportionate for the twelve-month period ended on December 31, 2019 compared with $0.9 million for the same period last year, a 140% increase due to:

- the addition of the Pampa Elvira solar facility, which was part of the investment in Energía Llaima in July 2018.

Adjusted EBITDA[1]

Stable at $103.3 million for the three-month period ended December 31, 2019
Up 16% to $409.2 million for the twelve-month period ended December 31, 2019



1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

For the three-month period ended on December 31, 2019, compared with the same period last year

The decrease in Adjusted EBITDA in the **hydroelectric** power generation segment is mainly due to:

- lower contribution from the British Columbia facilities attributable to a net unfavourable impact of lower production despite lower operational expenses due to the favourable settlement of the water rights claim; and
- lower revenues at the Quebec facilities.

The increase in Adjusted EBITDA in the **wind** power generation segment is due mainly to:

- higher revenues at the France wind facilities due to higher production;
- the commissioning of the Foard City wind farm in Texas on September 27, 2019; and
- higher revenues at the Quebec wind facilities due to higher production.

These items were partly offset by:

- lower revenues at the Mesgi'g Ugju's'n facility due to a lower production.

The increase in Adjusted EBITDA in the **solar** power generation segment is mainly due to:

- the energy produced and sold by the Phoebe solar facility during production ramp-up and the subsequent completion of commissioning activities on November 19, 2019.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

The decrease in Adjusted EBITDA from the **hydroelectric** power generation segment is due mainly to:

- lower contribution from the British Columbia facilities attributable to a net unfavourable impact of lower production despite higher average selling prices and lower operational expenses due to water rights claim; and
- lower revenues from the Quebec facilities.

The increase in Adjusted EBITDA in the **wind** power generation segment is due mainly to:

- higher revenues in Quebec due mainly to the 62% interest in the Cartier Wind Farms, acquired in October 2018;
- higher revenues at the France facilities from higher production; and
- the contribution of the Foard City wind farm since its commissioning on September 27, 2019.

The increase in Adjusted EBITDA in the **solar** power generation segment is mainly due to:

- the energy produced and sold by the Phoebe solar facility during production ramp-up and the subsequent completion of commissioning activities on November 19, 2019.

The increase in other operating, general and administrative and prospective expenses is mainly due to:

- higher general and administrative expenses related to the acquisitions and investments made in 2018.

This item is mostly offset by:

- a recovery for prospective project expenses previously incurred towards the Innavik hydro project and transferred to the joint venture in exchange for preferred units of the partnership under of an asset transfer agreement concluded between the parties.

Adjusted EBITDA Margin[1]

Down from 74.7% to 72.2% for the three-month period ended on December 31, 2019
Up from 73.2% to 73.5% for the twelve-month period ended on December 31, 2019

The decrease for the three-month period is mainly explained by:

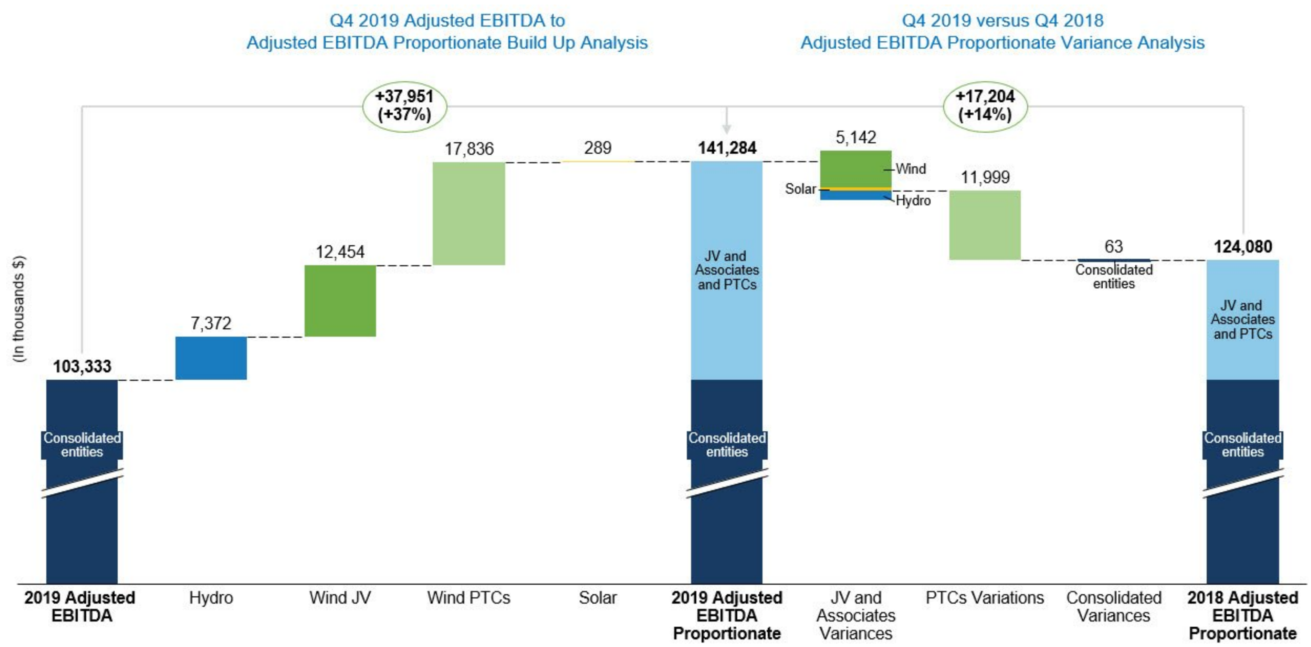
- lower production at the hydro facilities; and
- lower revenues at the Mesgi'g Ugju's'n facility due to lower production.

The increase for the twelve-month period is mainly explained by:

- changes in the mix of segments as wind and solar generation now represents a higher proportion of Adjusted EBITDA. Wind and solar activities typically have a better return on revenues than hydro due to lower operating costs.

1. Adjusted EBITDA Margin is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Adjusted EBITDA Proportionate[2]



2. Adjusted EBITDA Proportionate is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the three-month period ended on December 31, 2019, compared with the same period last year

The joint ventures' and associates' **hydroelectric facilities** contributed $7.4 million to the Adjusted EBITDA Proportionate in the fourth quarter of 2019, compared with $9.1 million for the same quarter last year, a 19% decrease mainly due to:

- lower contribution from the Chile facilities; and
- lower contribution from the Ontario facility due to lower revenues.

The joint ventures' and associates' **wind farms** contributed $12.5 million to the Adjusted EBITDA Proportionate for the fourth quarter of 2019, compared with a $6.1 million contribution in the same quarter last year, a 105% increase mainly due to:

- higher revenues at the Flat Top and Shannon facilities.

The proportional PTCs generated by the **wind farms** contributed $17.8 million in the fourth quarter of 2019, compared with a $5.8 million contribution in the same quarter last year. The increase is due to:

- PTCs generated by the Foard City wind farm following its commissioning on September 27, 2019; and
- higher generation at the Shannon and Flat Top wind farms.

The joint ventures' and associates' **solar farm** contributed $0.3 million to Adjusted EBITDA Proportionate in the fourth quarter of 2019 compared with a negative contribution of $0.2 million for the same quarter last year, a 259% increase due to:
- lower operating costs and higher revenues.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

The joint ventures' and associates' **hydroelectric facilities** contributed $48.0 million to the Adjusted EBITDA Proportionate for the twelve-month period ended on December 31, 2019, compared with $41.2 million for the same period last year, a 17% increase mainly due to:
- the investment in Energía Llaima in July 2018; and
- higher Adjusted EBITDA at the Jimmie Creek and Toba Montrose facilities due to higher revenues.

These items were partly offset by:
- lower contribution from the Ontario facility due to lower revenues.

The joint ventures' and associates' **wind farms** contributed $21.6 million to Adjusted EBITDA Proportionate for the twelve-month period ended on December 31, 2019, compared with $16.5 million for the same period last year, a 31% increase mainly due to:
- higher revenues at the Flat Top and Shannon wind farms; and
- higher contribution from the Dokie facility.

These items were partly offset by:
- higher overall operating expenses in joint ventures' and associates' wind facilities.

The proportional PTCs generated by the **wind farms** contributed $37.1 million in the twelve-month period ended on December 31, 2019, compared with a $19.1 million contribution in the same period last year. The increase is due to:
- higher generation at the Shannon and Flat Top wind farms; and
- PTCs generated by the Foard City wind farm following its commissioning on September 27, 2019.

The joint ventures' and associates' **solar farm** contributed $1.0 million to the Adjusted EBITDA Proportionate for the twelve-month period ended on December 31, 2019, compared with a negative contribution of $0.2 million for the same period last year. The Pampa Elvira solar facility was part of the investment in Energía Llaima in July 2018.

Finance Costs

Up 11% to $61.1 million for the three-month period ended December 31, 2019
Up 18% to $231.8 million for the twelve-month period ended December 31, 2019

The increase for the three-month period is mainly due to:
- interest expenses related to the Phoebe and Foard City project loans and tax equity financing;
- higher interest expenses stemming from the September 2019 4.65% Convertible Debentures offering; and
- higher interest expenses on lease liabilities (adoption of IFRS 16).

These items were partly offset by:
- the refinancing of the Yonne facility loan at a lower interest rate;
- interest on the temporary bridge loan that was fully repaid in the second quarter of 2019.

The increase for the twelve-month period period is due mainly to:
- interest expenses related to the acquisitions and investments made in 2018;
- interest expenses related to the Phoebe and Foard City project loans and tax equity financing.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 4.49% as at December 31, 2019 (4.48% as at December 31, 2018).

Other Net (Revenues) Expenses

Revenues of $102.0 million for the three-month period ended December 31, 2019
Revenues of $104.6 million for the twelve-month period ended December 31, 2019

The other net revenues for the three-month period are mainly due to:
- tax attributes allocated to the tax equity investors at the Foard City wind and Phoebe solar facilities, mainly related to the accelerated tax depreciation recognized under the U.S. Modified Accelerated Cost Recovery System ("MACRS");
- PTCs generated by the Foard City wind facility;

- penalty fees to be received for late delivery, by the contractor, of certain project milestones at the Phoebe solar facility; and
- gain on debt modification relating to the Stardale project refinancing.

These items were partly offset by:

- foreign exchange loss due to revaluation of monetary assets and liabilities.

The other net revenues for the twelve-month period are mainly due to:

- tax attributes allocated to the tax equity investors at the Foard City wind and Phoebe solar projects, mainly related to the accelerated tax depreciation recognized under the U.S. MACRS;
- PTCs generated by the Foard City wind facility;
- penalty fees to be received for late delivery, by the contractor, of certain project milestones at the Phoebe solar facility;
- EUR-CAD foreign exchange forward contracts that were settled under favourable conditions during the period, triggering a realized gain; and
- gain on debt modification relating to the Stardale project refinancing.

These items were partly offset by:

- restructuring costs related to centralizing the accounting functions at the head office;
- a provision for penalty related to the Glen Miller flood incident in the second quarter of 2019;
- liquidated damages under certain power purchase agreements in British Columbia; and
- foreign exchange loss due to revaluation of monetary assets and liabilities.

Depreciation and Amortization

Up 25% to $53.0 million for the three-month period ended December 31, 2019
Up 29% to $194.6 million for the twelve-month period ended December 31, 2019

The increases for the three- and twelve-month periods are mainly due to:

- the 62% acquired interest in the Cartier Wind Farms;
- the depreciation and amortization of the Foard City and Phoebe facilities since their commissioning; and
- the depreciation on right-of-use assets associated to the lease liabilities (adoption of IFRS 16).

Impairment of project development costs

On December 31, 2019, the Corporation conducted annual impairment tests on project development costs. Based on the results of these tests, an $8.2 million impairment charge was recognized on the Boswell project for which uncertainties exist regarding the timing and profitability of any development. For the year ended December 31, 2018, no impairment charge was recognized.

Share of Earnings of Joint Ventures and Associates

Share of earnings of $27.3 million for the three-month period ended December 31, 2019, compared with a share of earnings of $37.3 million for the corresponding period in 2018
Share of earnings of $36.5 million for the twelve-month period ended December 31, 2019, compared with a share of earnings of $47.6 million for the corresponding period in 2018

The decrease in the share of earnings of the joint ventures and associates allocated to Innergex for the three-month period is mainly due to:

- a cumulative adjustment related to a reclassification of the tax equity financing as a financial liability during the fourth quarter of 2019 and the comparative quarter, concurrently affecting the amount of earnings previously allocated to the tax equity investor; and
- a loss allocated to Innergex from the Energía Llaima joint venture compared to an allocation of earnings in 2018

The decrease was partly offset by:

- an increase in earnings allocated to Innergex from the Flat Top wind project due to an annual adjustment along with a favorable movement in the power prices affecting the fair value of the Flat Top power hedge, partly offset by the decrease in tax attributes allocated to the tax equity investor related to accelerated tax depreciation recognized under the U.S. Modified Accelerated Cost Recovery System ("MACRS"), which are mainly allocated in the first year of operations.

The decrease in the share of earnings of the joint ventures and associates allocated to Innergex for the twelve-month period is mainly due to:

- a loss allocated to Innergex from the Umbata Falls facility primarily related to an unrealized loss on financial instruments compared to an unrealized gain in the same period of 2018;
- a decrease in earnings allocated to Innergex from the Shannon wind farm due to an unfavourable movement in the power prices affecting the fair value of the Shannon power hedge; and
- a loss allocated to Innergex from the Energía Llaima joint venture compared to an allocation of earnings in 2018.

The decrease was partly offset by:

- an increase in earnings allocated to Innergex from the Flat Top wind project due to a favourable movement in the power prices affecting the fair value of the Flat Top power hedge, partly offset by the decrease in tax attributes allocated to the tax equity investor related to accelerated tax depreciation recognized under the U.S. Modified Accelerated Cost Recovery System ("MACRS"), which are mainly allocated in the first year of operations.

Unrealized Net Loss (Gain) on Financial Instruments

Unrealized net loss of $40.7 million for the three-month period ended December 31, 2019, compared with an unrealized net gain of $9.1 million for the corresponding period in 2018

Unrealized net loss of $49.9 million for the twelve-month period ended December 31, 2019, compared with an unrealized net gain of $13.0 million for the corresponding period in 2018

Derivatives are used by the Corporation to manage its exposure to interest rate risk on its existing and upcoming debt financing, to manage its exposure to foreign exchange risk, thereby protecting the economic value of its facilities, and to manage its exposure to electricity price risk for projects that deliver electricity at variable prices per MWh.

The unrealized net loss on financial instruments for the three-month period ended December 31, 2019 is mainly due to:

- an unfavourable impact related to the change in fair value of the Phoebe basis hedge;

This item was partly offset by:

- a favourable impact related to the change in fair value of the Phoebe power hedge, as recognized directly in earnings from October 1, 2019 onwards, following the cessation of hedge accounting as of that date; and
- an unrealized loss on the conversion of intragroup loans.

The unrealized net loss on financial instruments for the twelve-month period ended December 31, 2019, is due mainly to:

- an unfavourable impact related to the change in fair value of the Phoebe basis hedge;
- an unrealized loss on the conversion of intragroup loans; and
- the amortization of the accumulated losses from the pre-hedge accounting period.

These items were partly offset by:

- a favourable impact related to the change in fair value of the Phoebe power hedge, as recognized directly in earnings from October 1, 2019 onwards, following the cessation of hedge accounting as of that date;
- an unrealized gain on the EUR-CAD foreign exchange forward contracts, mainly derived from the following:
  - a favourable movement in EUR-CAD forward rates; partially offset by
  - contracts that were settled during the twelve-month period, triggering a realized gain recorded in other net (revenues) expenses.

Income Tax Expenses

Income tax expense of $117.7 million for the three-month period ended December 31, 2019

Income tax expense of $118.9 million for the twelve-month period ended December 31, 2019

For the three-month period ended December 31, 2019, the Corporation recorded :

- a current income tax recovery of $5.5 million ($4.1 million of current income tax expense for the corresponding period in 2018); and
- a deferred income tax expense of $123.2 million ($22.6 million for the corresponding period in 2018).

The current income tax recovery for the three-month period ended December 31, 2019, is mainly due to:

- a downward valuation of the taxable gain on an intercompany transaction related to the introduction of a tax equity investor in the Phoebe solar project; partly offset by
- the decrease in taxable income following the disposition of the Corporation's interest in the Icelandic assets.

The increase in the deferred income tax expense for the three-month period ended December 31, 2019 is mainly due to:

- tax attributes and PTCs allocated to tax equity investors by the Foard City wind and Phoebe solar projects, while less significant amounts were allocated in 2018 to tax equity investors by other tax equity project financings.

For the twelve-month period ended December 31, 2019, the Corporation recorded :

- a current income tax expense of $16.8 million ($8.5 million for the corresponding period in 2018); and
- a deferred income tax expense of $102.0 million ($18.7 million of deferred income tax recovery for the corresponding period in 2018).

The increase in the current income tax expenses for the twelve-month period ended December 31, 2019 is mainly due to:

- a taxable gain on an intercompany transaction related to the introduction of a tax equity investor in the Phoebe solar project and the increase in taxable income in France; partly offset by
- a decrease in taxable income following the disposition of the Corporation's interest in the Icelandic assets.

The increase in the deferred income tax expense for the twelve-month period ended December 31, 2019 is mainly due to:

- tax attributes and PTCs allocated to tax equity investors by the Foard City wind and Phoebe solar projects, while less significant amounts were allocated in 2018 to tax equity investors by other tax equity project financings.

Net (Loss) Earnings from continuing operations

Net loss of $48.0 million for the three-month period ended December 31, 2019
Net loss of $53.0 million for the twelve-month period ended December 31, 2019

For the three-month period ended December 31, 2019, the Corporation recorded a net loss from continuing operations of $48.0 million (basic and diluted net loss from continuing operations of $0.35 per share), compared with net earnings from continuing operations of $18.8 million (basic and diluted net earnings from continuing operations of $0.11 per share) for the corresponding period in 2018.

The $66.9 million variation can be explained by:

- a $91.0 million increase in income tax expenses;
- a $49.8 million unfavourable variation in unrealized net loss (gain) on financial instruments;
- a $10.7 million increase in depreciation and amortization;
- a $10.0 million decrease in the share of earnings of joint ventures and associates;
  a $8.2 million impairment of project development costs; and
- a $6.0 million increase in finance costs.

These items were partly offset by:

- a $108.9 million increase in other net revenues; and
- a $0.1 million increase in Adjusted EBITDA.

For the twelve-month period ended December 31, 2019, the Corporation recorded a net loss from continuing operations of $53.0 million (basic and diluted net loss from continuing operations of $0.40 per share), compared with net earnings from continuing operations of $26.2 million (basic and diluted net earnings from continuing operations of $0.20 per share) for the corresponding period in 2018.

The $79.2 million variation can be explained by:

- a $91.6 million increase in income tax recovery;
- a $62.9 million unfavourable variation in unrealized net loss (gain) on financial instruments;
- a $43.3 million increase in depreciation and amortization;
- a $35.9 million increase in finance costs;
- an $11.1 million decrease in the share of earnings of joint ventures and associates; and
- an $8.2 million impairment of project development costs.

These items were partly offset by:

- a $116.8 million increase in other net revenues; and
- a $57.0 million increase in Adjusted EBITDA.

Adjusted Net (Loss) Earnings from continuing operations

Up to $25.4 million for the three-month period ended December 31, 2019
Up to $25.8 million for the twelve-month period ended December 31, 2019

When evaluating its operating results and to provide a more accurate picture of them, a key performance indicator for the Corporation is Adjusted Net (Loss) Earnings from continuing operations. Adjusted Net (Loss) Earnings from continuing operations is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with measures presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Impact on net (loss) earnings of financial instruments	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Net (loss) earnings from continuing operations	(48,049)	18,816	(53,026)	26,215
Add (Subtract):				
Unrealized net loss (gain) on financial instruments	40,708	(9,061)	49,933	(12,958)
Realized (gain) loss on financial instruments	(241)	6,914	(2,662)	6,092
Impairment of project development costs	8,184	—	8,184	—
Income tax (recovery) expenses related to above items	(9,427)	2,896	(10,117)	4,951
Share of unrealized net gain on financial instruments of joint ventures and associates, net of related income tax	(16,549)	(10,193)	(18,129)	(10,337)
Adjusted Net (Loss) Earnings from continuing operations	(25,374)	9,372	(25,817)	13,963

Excluding the impact of loss (gain) on financial instruments, the impairment of project development costs, the related income taxes and the share of joint ventures and associates on these elements, Adjusted Net Earnings from continuing operations for the three-month period ended December 31, 2019, would have been $25.4 million, compared with $9.4 million in 2018.

Excluding the impact of loss (gain) on financial instruments, the impairment of project development costs, the related income taxes and the share of joint ventures and associates on these elements, Adjusted Net Loss from continuing operations for the twelve-month period ended December 31, 2019, would have been $25.8 million, compared with Adjusted Net Earnings from continuing operations of $14.0 million in 2018.

Non-controlling Interests

Attribution of losses of $1.2 million for the three-month period ended December 31, 2019, compared with an attribution of losses of $0.6 million for the corresponding period in 2018

Attribution of losses of $3.2 million for the twelve-month period ended December 31, 2019, compared with an attribution of losses of $5.4 million for the corresponding period in 2018

Non-controlling interests are related to the non-wholly owned subsidiaries identified in the "Overview" section and to Creek Power Inc. and subsidiaries ("Creek Power"), which is wholly owned since May 15, 2018.

The attribution of loss from continuing operations to non-controlling interests of $1.2 million for the three-month period ended December 31, 2019, compared with an attribution of earnings of $3.0 million last year resulted mainly from:

- a cumulative adjustment related to a reclassification of the tax equity financing as a financial liability during the fourth quarter of 2019 and the comparative quarter, concurrently affecting the amount of earnings previously allocated to the tax equity investor;
- an allocation of loss at Harrison Hydro L.P. compared to an allocation of earnings in 2018, mainly stemming from lower revenues;
- a lower allocation of earnings at the Mesgi'g Ugju's'n wind farm mainly due to a decrease in revenues.

These items were partly offset by:

- net earnings in Innergex Europe, mostly explained by

The attribution of loss from discontinued operations of nil for the three-month period ended December 31, 2019, compared with $2.4 million for the corresponding period in 2018 is mainly explained by the completion of the sale of HS Orka in May 2019.

The attribution of loss from continuing operations to non-controlling interests of $5.3 million for the twelve-month period ended December 31, 2019, compared with $5.6 million last year, resulted mainly from:

- the absence of loss allocated to Creek Power due to the acquisition of the remaining ownership interests; partly offset by
- lower revenues at Harrison Hydro L.P. and its subsidiaries; and

The attribution of earnings from discontinued operations to non-controlling interests of $2.1 million for the twelve-month period ended December 31, 2019, compared with $0.2 million for the corresponding period in 2018, is mainly explained by:

- the current period representing the results of 143 days of operation prior to completion of the sale of HS Orka in May 2019, compared to the comparative period representing the results of 329 days subsequent to the acquisition of Alterra and its subsidiaries, including HS Orka, in February 2018.

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

GEOGRAPHIC SEGMENTS

As at December 31, 2019, and excluding its investments in joint ventures and associates, which are accounted for using the equity method, the Corporation had interests in the following operating facilities: 29 hydroelectric facilities, six wind farms and one solar farm in Canada, 15 wind farms in France and one hydroelectric facility, one wind farm and three solar farms in the United States. The Corporation operates in four principal geographical areas, which are detailed below.

	Three months ended December 31		Year ended December 31	
	2019[1]	2018	2019[1]	2018
Revenues				
Canada	96,932	111,701	435,069	387,679
France	31,061	26,022	94,474	87,016
United States	15,123	529	27,499	6,723
	143,116	138,252	557,042	481,418

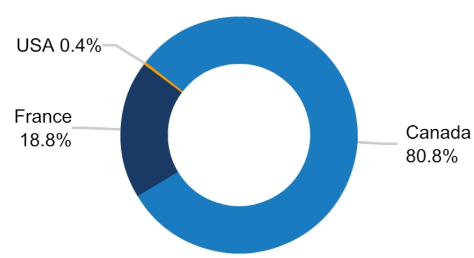
1. The Phoebe solar project contributions take into account ramp-up of production up to its full commissioning on November 19, 2019 and revenues since that.

	As at	
	December 31, 2019	December 31, 2018
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,629,942	3,757,207
France	891,764	956,214
United States	1,293,983	555,350
Chile	142,268	154,299
	5,957,957	5,423,070

1. Includes the investments in joint ventures and associates.

Q4 2019 Revenues by Country

Q4 2018 Revenues by Country (Restated)



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

Canada

Revenues down 13% to $96.9 million for the three-month period ended December 31, 2019
Revenues up 12% to $435.1 million for the twelve-month period ended December 31, 2019

Non-current assets, excluding derivative financial instruments and deferred tax assets, down 3% to $3,629.9 million at December 31, 2019, compared with December 31, 2018

The decrease in Canadian revenues for the three-month period is attributable mainly to:

- lower production at the British Columbia facilities;
- lower average selling price at some hydro Quebec facilities combined with lower production in few facilities; and
- lower revenues at the Mesgi'g Ugju's'n facility due to lower production.

These items were partly offset by:

- the 62% acquired interest in the Cartier Wind Farms.

The increase in Canadian revenues for the twelve-month period is attributable mainly to:

- the 62% acquired interest in the Cartier Wind Farms.

This item was partly offset by:

- lower revenues in British Columbia due to a net unfavourable impact of lower production over higher average selling prices at some facilities; and
- lower revenues at the Quebec hydro facilities due to lower average selling prices at some facilities.

The decrease in non-current assets, excluding derivative financial instruments and deferred income tax assets in Canada, is attributable mainly to:

- depreciation of property, plant and equipment, and amortization of intangible assets.

This item was partly offset by:

- an increase in assets due to the adoption of IFRS 16; and
- an increase in the asset retirement obligations due to a decrease in interest rate curves.

France

Revenues up 19% to $31.1 million for the three-month period ended December 31, 2019
Revenues up 9% to $94.5 million for the twelve-month period ended December 31, 2019

Non-current assets, excluding derivative financial instruments and deferred tax assets, down 7% to $891.8 million at December 31, 2019 compared to December 31, 2018

The increases in France revenues for the three- and twelve-month periods are attributable mainly to:

- higher production at the France wind facilities.

The decrease in non-current assets, excluding derivative financial instruments and deferred income tax assets in France, is attributable mainly to:

- a decrease in the EUR-CAD exchange rates; and
- depreciation of property, plant and equipment, and amortization of intangible assets.

These items were partly offset by:

- an increase in assets due to the adoption of IFRS 16; and
- an increase in the asset retirement obligations due to a decrease in interest rate curves.

United States

Revenues up to $15.1 million for the three-month period ended December 31, 2019
Revenues up to $27.5 million for the twelve-month period ended December 31, 2019

Non-current assets, excluding derivative financial instruments and deferred tax assets, up 133% to $1,294.0 million at December 31, 2019, compared with December 31, 2018

The increases in US revenues for the three- and twelve-month periods are attributable mainly to:

- the energy produced and sold by the Phoebe solar facility during production ramp-up and the subsequent completion of commissioning activities on November 19, 2019; and
- the contribution of the Foard City wind facility, commissioned on September 27, 2019.

The increase in non-current assets, excluding derivative financial instruments and deferred income tax assets in the United States is attributable mainly to:

- property, plant and equipment additions related to the construction of the Phoebe and Hillcrest solar projects and the Foard City wind facility;

- an increase in assets due to the adoption of IFRS 16; and
- new asset retirement obligations created in relation to the construction of the Phoebe solar project and the Foard City wind facility.

These items were partly offset by:

- a decrease in the USD-CAD exchange rates; and
- depreciation of property, plant and equipment, and amortization of intangible assets.

Chile

Non-current assets, excluding derivative financial instruments and deferred tax assets, down 8% to $142.3 million at December 31, 2019, compared with December 31, 2018

The Corporation's investment in Energía Llaima in Chile is accounted for using the equity method; therefore its revenues are not consolidated.

For the period ended December 31, 2019, the decrease in non-current assets is attributable to:

- a foreign exchange loss in the Energía Llaima investment recorded as a comprehensive loss; and
- a net loss in Energía Llaima.

DISCONTINUED OPERATIONS FINANCIAL RESULTS

	Three months ended December 31, 2019			Three months ended December 31, 2018		
	Innergex[1]	HS Orka[2]	Total	Innergex[1]	HS Orka[2]	Total
Production	1,793,803	—	1,793,803	1,396,066	351,642	1,747,708
Revenues	143,116	—	143,116	138,252	27,906	166,158
Adjusted EBITDA[3]	103,333	—	103,333	103,270	9,832	113,102
Net (loss) earnings	(48,049)	644	(47,405)	18,816	(4,575)	14,241

1. Equivalent to continuing operations.
2. Equivalent to discontinued operations.
3. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

	Twelve months ended December 31, 2019			Twelve months ended December 31, 2018		
	Innergex[1]	HS Orka[2]	Total	Innergex[1]	HS Orka[2]	Total
Production	6,509,622	545,424	7,055,046	5,086,497	1,196,939	6,283,436
Revenues	557,042	40,006	597,048	481,418	95,198	576,616
Adjusted EBITDA[3]	409,175	13,291	422,466	352,179	32,902	385,081
Net (loss) earnings	(53,026)	21,815	(31,211)	26,215	(497)	25,718

1. Equivalent to continuing operations.
2. Equivalent to discontinued operations.
3. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

	Total CAD
Consideration received, net of transaction costs:	
Cash consideration (US$299,910)	404,219
Consideration paid for working capital adjustment (US$2,042)	(2,695)
Transaction costs	(6,634)
Total disposal consideration, net of transaction costs	394,890
Carrying amount of net assets sold	331,147
Gain on sale before reclassification of foreign currency translation differences	63,743
Reclassification of foreign currency translation differences	46,015
Gain on sale	17,728

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

	As at May 23, 2019
Current assets	37,039
Non-current assets	855,734
	892,773
Current liabilities	71,976
Non-current liabilities	228,804
Total liabilities	300,780
Equity attributable to owners of the parent	331,147
Non-controlling interests	260,846
Total shareholders' equity	591,993
Total liabilities and shareholders’ equity	892,773

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

SHARE CAPITAL STRUCTURE

Information on Capital Stock

Number of Common Shares Outstanding

	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Weighted average number of common shares (in 000s)	139,105	132,753	134,658	130,030
Weighted average number of common shares (in 000s)				
Effect of share options issue	—	556	—	674
Effect of shares held in trust related to the PSP plan	—	203	—	203
	139,105	133,512	134,658	130,907
Shares that may be issued from the following equity instruments that are excluded from the potentially dilutive elements (in 000s):				
Effect of shares held in trust related to the PSP plan	223	—	301	203
Share options	301	203	170	—
Convertible debentures	13,777	14,167	13,777	14,167
	14,301	14,370	14,248	14,370

1. Share options for which the exercise price was below the average market price of common shares are included in the calculation of potentially dilutive equity instruments. Contingent share issuances have an anti-dilutive effect on loss per share.

The Corporation's Equity Securities

	As at		
	February 26, 2020	December 31, 2019	December 31, 2018
Number of common shares	174,054,386	139,405,832	132,986,850
Number of 4.75% convertible debentures	150,000	150,000	150,000
Number of 4.65% convertible debentures	125,000	143,750	—
Number of 4.25% convertible debentures	—	—	100,000
Number of Series A Preferred Shares	3,400,000	3,400,000	3,400,000
Number of Series C Preferred Shares	2,000,000	2,000,000	2,000,000
Number of share options outstanding	737,977	737,977	2,782,599

As at the closing of the market on February 26, 2020, and since December 31, 2019, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 34,636,823 common shares to Hydro-Québec under a private placement of common shares of Innergex as well as the issuance of 11,731 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at December 31, 2019, the increase in the number of common shares since December 31, 2018, was attributable mainly to the conversion of a portion of the 4.25% Convertible Debentures into 5,776,795 common shares as well as the issuance of 472,737 common shares following the cashless exercise of 2,122,764 options and of 169,450 common shares related to the DRIP.

Dividends

The Corporation's dividend policy is determined by its Board of directors and is based on the Corporation's operating results, cash flows, financial condition, debt covenants, long-term growth prospects, solvency test imposed under corporate law for the declaration of dividends and other relevant factors.

The following dividends were declared by the Corporation:

	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Dividends declared on common shares[1]	24,396	22,608	95,046	90,215
Dividends declared on common shares ($/share)	0.175	0.170	0.700	0.680
Dividends declared on Series A Preferred Shares	767	767	3,067	3,067
Dividends declared on Series A Preferred Shares ($/share)	0.2255	0.2255	0.9020	0.9020
Dividends declared on Series C Preferred Shares	719	719	2,875	2,875
Dividends declared on Series C Preferred Shares ($/share)	0.3594	0.3594	1.4375	1.4375

1. The increase in dividends declared on common shares is attributable to the increase in quarterly dividend, to the issuance of shares following the exercise of share options and to the issuance of shares under the DRIP.

The following dividends will be paid by the Corporation on April 15, 2020:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
02/27/2020	3/31/2020	4/15/2020	0.1750	0.2255	0.359375

On February 27, 2020, the Board of Directors increased the quarterly dividend from $0.175 to $0.180 per common share, corresponding to an annual dividend of $0.72 per common share. This is the seventh consecutive $0.02 annual dividend increase.

Normal Course Issuer Bid

On May 21, 2019, Innergex announced that it had received approval from the Toronto Stock Exchange (TSX) to proceed with a normal course issuer bid on its common shares (the "New Bid"). Under the New Bid, the Corporation is authorized to purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.5% of the 133,559,963 issued and outstanding common shares of the Corporation as at May 15, 2019. The New Bid commenced on May 24, 2019 and will terminate on May 23, 2020. Prior to December 31, 2019, no common shares were neither purchased nor cancelled.

On August 15, 2017, the Corporation announced that it had received approval from the TSX to proceed with a normal course issuer bid on its Common Shares (the "Bid") which commenced on August 17, 2017, and was terminated on August 16, 2018. The Corporation was authorized to purchase for cancellation up to 2,000,000 of its Common Shares, representing to approximately 1.84% of the 108,640,790 issued and outstanding Common Shares as at August 14, 2017. Under the Bid, the Corporation purchased for cancellation 697,212 Common Shares at an average price of $13.60 per share, for an aggregate consideration of $9.5 million during the year ended December 31, 2018.

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

FINANCIAL POSITION

As at	December 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	156,224	79,586
Restricted cash	39,451	29,981
Other current assets	109,957	118,710
Total current assets	305,632	228,277
Non-current assets		
Property, plant and equipment	4,620,025	4,470,663
Intangible assets	682,227	925,009
Investments in joint ventures and associates	511,899	651,912
Goodwill	60,666	109,995
Other non-current assets	191,655	130,302
Total non-current assets	6,066,472	6,287,881
Total assets	6,372,104	6,516,158
LIABILITIES		
Current liabilities	641,353	641,292
Non-current liabilities		
Long-term loans and borrowings	4,281,586	4,262,469
Other non-current liabilities	833,839	670,360
Total non-current liabilities	5,115,425	4,932,829
Total liabilities	5,756,778	5,574,121
SHAREHOLDERS' EQUITY		
Equity attributable to owners	604,384	629,261
Non-controlling interests	10,942	312,776
Total shareholders' equity	615,326	942,037
	6,372,104	6,516,158

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

Working Capital Items

Current assets

Current assets amounted to $305.6 million as at December 31, 2019, compared with $228.3 million as at December 31, 2018, an increase of $77.4 million due mainly to:

- an increase of $9.5 million in restricted cash, mainly due to the $24.7 million related to the contribution received from the Corporation's tax equity partner in the Phoebe solar facility; and
- an increase of $76.6 million in cash and cash equivalents derived from operating, financing and investing activities.

This increase was partly offset by:

- a decrease of $11.6 million in accounts receivable stemming primarily from the sale of HS Orka, partly offset by higher revenues in December 2019 compared to December 2018.

Current liabilities

Current liabilities amounted to $641.4 million as at December 31, 2019, compared with $641.3 million as at December 31, 2018, a decrease of $0.1 million due mainly to:

- a $32.3 million decrease in the current portion of the long-term debt and other liabilities due to:
  - the repayment of the $228.0 million one-year credit facility contracted on October 24, 2018 at the time of the acquisition of the remaining interest in the Cartier Wind Farms and Operating Entities; and
  - the remediation of the Valottes, Porcien and Beaumont project loans following their reclassification as current liabilities on December 31, 2018 after failing to fulfill the loans' minimum debt service coverage ratio.

This decrease was partially offset by:

- an increase in accounts payable of $11.3 million arising mainly from the construction of the Foard City wind and Phoebe solar facilities, partly offset by a decrease in accounts payable stemming from the sale of HS Orka; and
- an increase in derivative financial instruments of $21.1 million mainly due to the new Phoebe project basis hedge contracted on August 2, 2019; and
- Mesgi'g Ugju's'n loan of $232.1 million reallocated to the current portion of long-term debt.

Working capital was negative at $335.7 million, as at December 31, 2019, with a working capital ratio of 0.48:1.00 (as at December 31, 2018, working capital was negative at $413.0 million, with a working capital ratio of 0.36:1.00), an improvement of $77.3 million due to the items explained above.

The Corporation considers its current level of working capital to be sufficient to meet its needs. As at December 31, 2019, the Corporation had $700.0 million in revolving term credit facilities and had drawn $490.8 million as cash advances, while $47.1 million had been used to issue letters of credit, leaving $161.9 million available.

Non-current assets

Non-current assets amounted to $6,066.5 million as at December 31, 2019, compared to $6,287.9 million as at December 31, 2018, a decrease of $221.4 million mainly due to:

- a $855.7 million decrease stemming from the sale of HS Orka;
- depreciation and amortization; and
- a strengthening of the Canadian dollar against the Euro and the US dollar.

These items were partly offset by:

- a $709.1 million increase in property, plant and equipment due mainly to the construction activities related to the Foard City and Phoebe facilities;
- a $123.9 million increase in property, plant and equipment stemming from the initial application of IFRS 16 (please refer to the "Change in Accounting Policies" section);
- a $68.4 million increase in derivative financial instruments mainly related to the Phoebe power hedge; and
- a $13.8 million increase in deferred tax assets primarily related to a deductible temporary difference registered on ITCs funding for the Phoebe solar facility.

Non-current liabilities

Non-current liabilities amounted to $5,115.4 million as at December 31, 2019, compared with $4,932.8 million as at December 31, 2018, an increase of $182.6 million mainly due to:

- a $211.0 million net increase in long-term debt mainly due to:
  - a $335.8 million funding from tax equity investors of the Foard City and Phoebe facilities, net of ITCs, PTCs and tax attributes allocated, and cash distributions made; and
  - a $23.0 million net increase following the refinancing of the Yonne facility long-term debt;

  These items were partly offset by:
  - reimbursements of Phoebe and Foard City construction loans net of additional draws made upon commissioning of both facilities;
  - net repayments made on the corporate revolving facilities, including repayments made with the proceeds received from the sale of HS Orka;
  - scheduled principal repayments on long-term debt; and
  - a strengthening of the Canadian dollar against the Euro and the US dollar.
- a $117.2 million increase in lease liabilities stemming from the initial application of IFRS 16 (please refer to the "Change in Accounting Policies" section);
- a $118.4 million increase in deferred tax liabilities, mainly related to tax attributes and PTCs allocated to tax equity investors from the commissioning of the Foard City wind project and other tax equity project financings;
- a $32.7 million increase in asset retirement obligations mainly related to the construction activities at the Foard City and Phoebe facilities, and an increase in fair value of existing asset retirement obligations due to a decrease in interest rates curves;
- a $40.2 million increase in the liability portion of the convertible debentures stemming from the completion of a $125 million convertible debenture offering and redemption offering for the 4.25% Convertible Debentures.

These items were partly offset by:

- a $229.4 million decrease stemming from the sale of HS Orka.

As at December 31, 2019, the Corporation and its subsidiaries have met all material financial and non-financial conditions, unless indicated below, related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements, trust indentures, 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. As at December 31, 2019, Mesgi'g Ugju's'n project was in default of its credit agreement. A breach was triggered by the bankruptcy of a supplier considered a major project participant under the credit agreement. A waiver has been obtained and was subsequently extended until March 31, 2020. A plan was put in place to ensure the continuity of the operations of the project. Ongoing dialogue and reporting are provided to the project Lenders until this situation is resolved. The project was in compliance of financial covenants. If the waiver is not renewed, the lender would have the right to request repayment, the $232.1 million loan was reallocated to the current portion of long-term debt.

Derivative Financial Instruments and Risk Management

The Corporation uses derivative financial instruments ("derivatives") to manage its exposure to the risk of increasing interest rates on its debt financing, to manage its exposure to exchange rate fluctuations on the future repatriation of cash flows from its French operations, and to reduce exposure to the risk of decreasing power prices.

		Current Notional		Fair Value After Credit Adjustment	
As at September 30, 2019	Currency	Currency of origin	CAD	Currency of origin	CAD
Interest rate swaps	CAD	1,172,186	1,172,186	(50,445)	(50,445)
Interest rate swaps	USD	129,204	167,811	(12,376)	(16,074)
Interest rate swaps	EUR	104,592	152,527	(11,669)	(17,017)
Foreign exchange forward contracts	EUR VS CAD	307,897	535,535	(24,269)	(24,269)
Power and basis Hedges	USD	N/A	N/A	21,371	27,757
				(77,388)	(80,048)

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

Shareholders' Equity

Shareholders' equity amounted to 615.3 million as at December 31, 2019, compared with 942.0 million as at December 31, 2018, a decrease of $326.7 million mainly due to:

- a $260.8 million decrease in non-controlling interests stemming from the sale of HS Orka;
- dividends declared on common and preferred shares totaling $100.9 million; and
- distributions declared to non-controlling interests of $14.6 million.

These items are partly offset by:

- the $(35.4) million total comprehensive income of the period; and
- the conversion of convertible debentures into common shares totaling $86.7 million.

Contractual obligation

As at December 31, 2019, the expected schedule of commitment payments is as follows:

Year of expected payment	Under 1 year	1 to 5 years	Thereafter	Total
Long-term loans and borrowings	411,472	1,456,851	2,901,828	4,770,151
Interest on long-term loans and borrowings	250,683	556,959	1,506,110	2,313,752
Lease obligations	7,841	39,462	155,494	202,797
Purchase obligations	53,649	142,182	276,622	472,453
Operating lease contracts	8,892	44,214	19,763	72,869
Total	732,537	2,239,668	4,859,817	7,832,022

Contingencies

On March 23, 2017, the Comptroller of the Water Rights issued adjusted rental statements to the Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012 for an amount of $3.3 million in aggregate regarding water rental rates to be charged under the Water Act. The amount claimed was paid under protest and Harrison Hydro L.P. and its subsidiaries filed a notice of appeal of the decision to the Environmental Appeal Board.

On July 26, 2019, the Environmental Appeal Board of British Columbia rendered a decision granting the appeal and ordering the Comptroller of Water Rights to reimburse to each of the Limited Partnerships its proportionate share of the adjusted water rental amounts of $3.2 million overcharged to Harrison for the years 2011 and 2012. On November 22, 2019, the Environmental Appeal Board of British Columbia rendered another decision confirming that the sum will accrue interest starting June 28, 2017 until the date it is refunded to the Appellants. On January 20, 2020, the Comptroller of Water Rights filed with the Supreme Court of British Columbia a petition for judicial review of the Environmental Appeal Board's order to return the amount in water rental fees to the Appellants, with interest. On January 31, 2020, the Comptroller of Water Rights transferred an amount of $3.3 million, representing the principal of $3.2 million with interest accrued between June 28, 2017 and January 31, 2020, to a trust account established by the Appellants' external legal counsel, bearing interest in favour of the Appellants. The Corporation recognized the amount in the fiscal 2019 consolidated statements of earnings against Operating expenses.

Off-Balance-Sheet Arrangements

As at December 31, 2019, the Corporation had issued letters of credit totaling $161.9 million, including $101.4 million from its available corporate facilities, to meet its obligations under its various PPAs and other agreements. These letters of credit were issued as payment securities for various projects under construction and as performance or financial guarantees under PPAs and other contractual obligations. As at that date, Innergex had also issued a total of $110.4 million in corporate guaranties used mainly to guarantee the long-term currency hedging instruments of its operations in France. The corporate guaranties were also used to support the performance of the Brown Lake and Miller Creek hydroelectric facilities, the post-commissioning activities at the Mesgi'g Ugju's'n facility, the Foard City wind facility and the Griffin Trail, and other prospective projects.

Tax equity investors in U.S. projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investments at Shannon, Kokomo, Spartan, Flat Top, Phoebe and Foard City, Alterra, a subsidiary of Innergex, has executed guaranties effective on funding of the tax equity investments indemnifying the tax equity investors against certain breaches of project-level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters that are substantially under its control and are very unlikely to occur. With respect to the Phoebe facility, Alterra has also provided a guarantee to the lenders related to debt-service payments, which will become effective only in the unlikely event that the Phoebe tax equity investors call upon their corresponding guarantee.

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

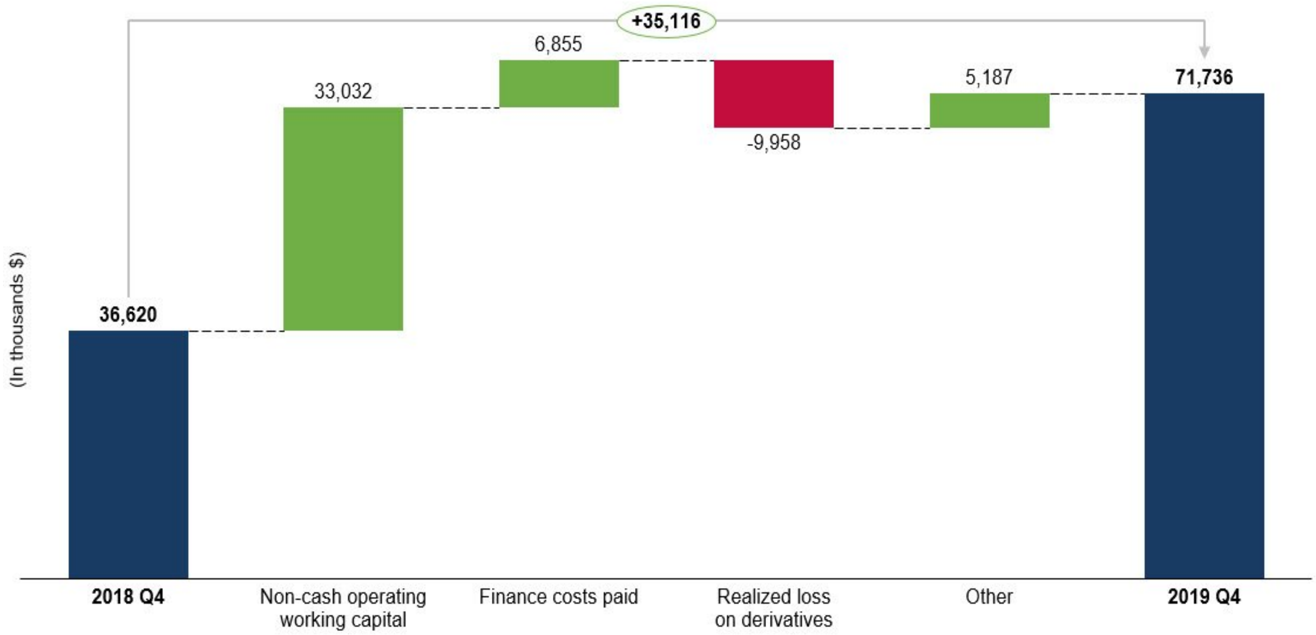
LIQUIDITY AND CAPITAL RESOURCES

	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
OPERATING ACTIVITIES				
Cash flows from operating activities from continuing operations before changes in non-cash operating working capital items	41,378	39,294	204,541	184,595
Changes in non-cash operating working capital items	30,358	(2,674)	22,402	(8,648)
Cash flows from operating activities from continuing operations	71,736	36,620	226,943	175,947
Cash flows from operating activities from discontinued operations	—	8,636	13,122	33,443
	71,736	45,256	240,065	209,390
FINANCING ACTIVITIES				
Cash flows from financing activities from continuing operations	76,202	652,279	368,548	960,589
Cash flows from financing activities from discontinued operations	—	(1,192)	20,059	8,382
	76,202	651,087	388,607	968,971
INVESTING ACTIVITIES				
Cash flows from investing activities from continuing operations	(136,331)	(687,145)	(516,997)	(1,130,286)
Cash flows from investing activities from discontinued operations	—	(11,418)	(31,957)	(30,577)
	(136,331)	(698,563)	(548,954)	(1,160,863)
Effects of exchange rate changes on cash and cash equivalents	(1,018)	(97)	(3,080)	174
Net change in cash and cash equivalents	10,589	(2,317)	76,638	17,672
Cash and cash equivalents, beginning of period	145,635	81,903	79,586	61,914
Cash and cash equivalents, end of year	156,224	79,586	156,224	79,586

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

Cash Flows from Operating Activities from Continuing Operations

Up $35.1 million to $71.7 million for the three-month period ended December 31, 2019
Up $51.0 million to $226.9 million for the twelve-month period ended December 31, 2019



For the three-month period ended on December 31, 2019, compared with the same period last year

The increase in cash flows from operating activities from continuing operations is primarily attributable to:

- a $6.9 million decrease in finance costs paid, due in part to the lower average indebtedness during the quarter and the timing of payments;
- a $33.0 million favourable change in non-cash operating working capital items, due mainly to:
  - a $20.0 million favourable variation in non-cash operating working capital changes from accounts payable and other payables; and
  - a $17.1 million favourable variation in non-cash operating working capital changes from accounts receivable.

These items were partly offset by:

- a $16.1 million realized loss on settlement of financial instruments, $11.7 million of which relates to the Phoebe basis hedge due to unfavourable basis differentials outside of the generation hours, compared to a $6.1 million realized loss in the comparative period, mainly related to the settlement of interest rate swaps after restructuring the Cartier Energie project loan following the acquisition of the Cartier Wind Farms during the fourth quarter of 2018.

Discontinued operations contributed to increasing cash flows from operating activities in the three-month period ended on December 31, 2018 by $8.6 million, compared with nil in 2019.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

The increase in cash flows from operating activities from continuing operations is primarily attributable to:

- a $57.0 million increase in Adjusted EBITDA[1];
- a $31.1 million favourable change in non-cash operating working capital items, due mainly to:
  - a $49.3 million favourable variation in non-cash operating working capital changes from accounts payable and other payables; partly offset by:
  - a $14.6 million unfavourable variation in non-cash operating working capital changes from accounts receivable

These items were partly offset by:

- a $25.0 million increase in finance costs paid, mainly due to the higher average indebtedness during the year;
- a $12.6 million increase in income taxes paid, largely related to a payment made toward the current income tax expense on the taxable gain realized following an intercompany transaction related to the introduction of a tax equity investor in the Phoebe solar facility; and

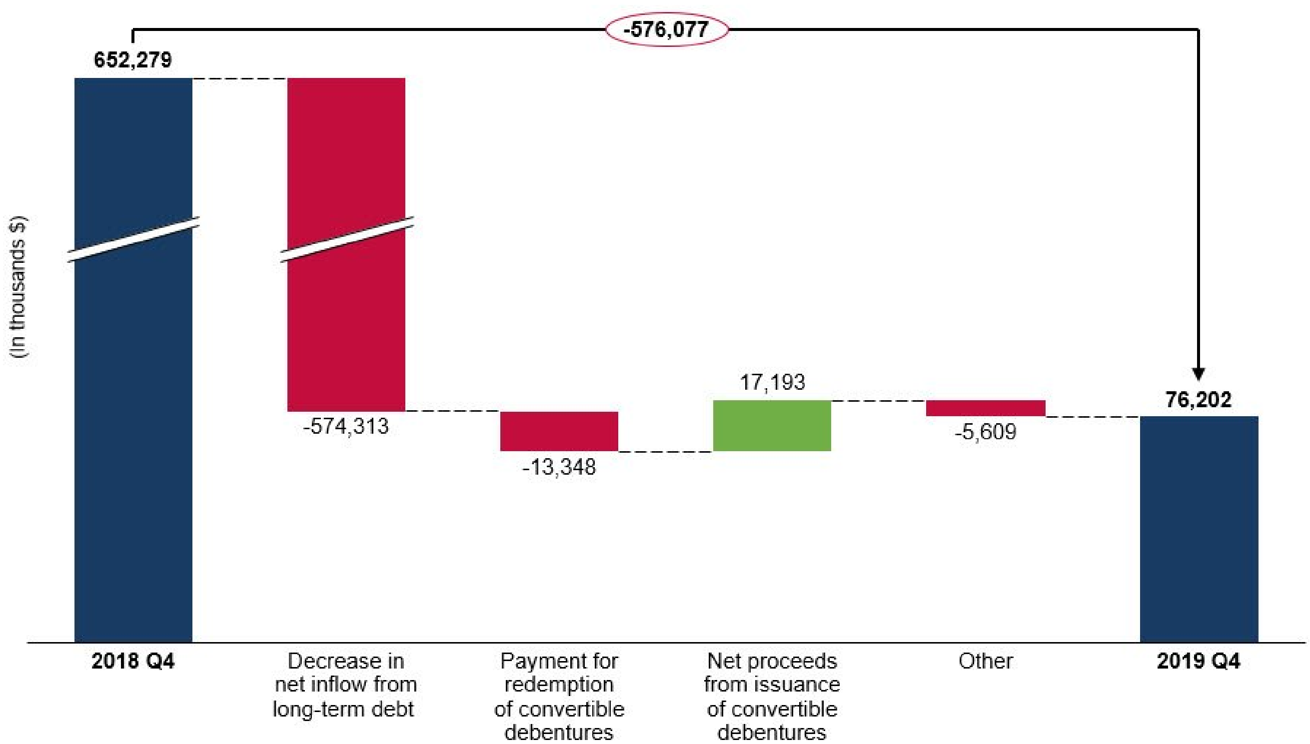
- a $16.1 million realized loss on settlement of financial instruments, $11.7 million of which relates to the Phoebe basis hedge due to unfavourable basis differentials outside of the generation hours, compared to a $6.1 million realized loss in the comparative period, mainly related to the settlement of interest rate swaps after restructuring the Cartier Energie project loan following the acquisition of the Cartier Wind Farms during the fourth quarter of 2018;

Discontinued operations also contributed to decrease cash flows from operating activities by $20.3 million, from $33.4 million in 2018 to $13.1 million in 2019.

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Cash Flows from Financing Activities from Continuing Operations

Cash inflow down $576.1 million to $76.2 million for the three-month period ended December 31, 2019
Cash inflow down $592.0 million to $368.5 million for the twelve-month period ended December 31, 2019



For the three-month period ended on December 31, 2019, compared with the same period last year

The decrease in cash flows from financing activities from continuing operations stems mainly from:

- a 574.3 million decrease in the net cash inflow from long-term debt, from a $675.8 million net increase in long-term debt in 2018, to a $101.5 million net increase in long-term debt in 2019.
  The $101.5 million net increase in long-term debt in 2019 is mainly attributable to:
  - a $167.0 million net increase in the revolving credit facility; and
  - a $23.0 million net increase in the Yonne project loan facility following its refinancing.

  The above increases related to long-term debt were partly offset by:
  - a net decrease of $43.7 million in Phoebe project financing due to the repayment of the construction loan from the tax equity financing and the conversion of the bridge loan into a term loan; and
  - scheduled repayments of project loans;
- a $13.3 million decrease from the redemption of the 4.25% Convertible Debentures;
- a $17.2 million increase from the issuance of convertible debentures in the third quarter of 2019, while no issuance occurred during the same period of 2018.

Discontinued operations also contributed to decreasing cash flows from financing activities in the three-month period ended on December 31, 2018 by $1.2 million, compared with nil in 2019.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

The decrease in cash flows from financing activities from continuing operations stems mainly from:

- a $552.3 million decrease in the net cash inflow from long-term debt, from a $915.4 million net increase in long-term debt in 2018, to a $363.1 million net increase in long-term debt in 2019.

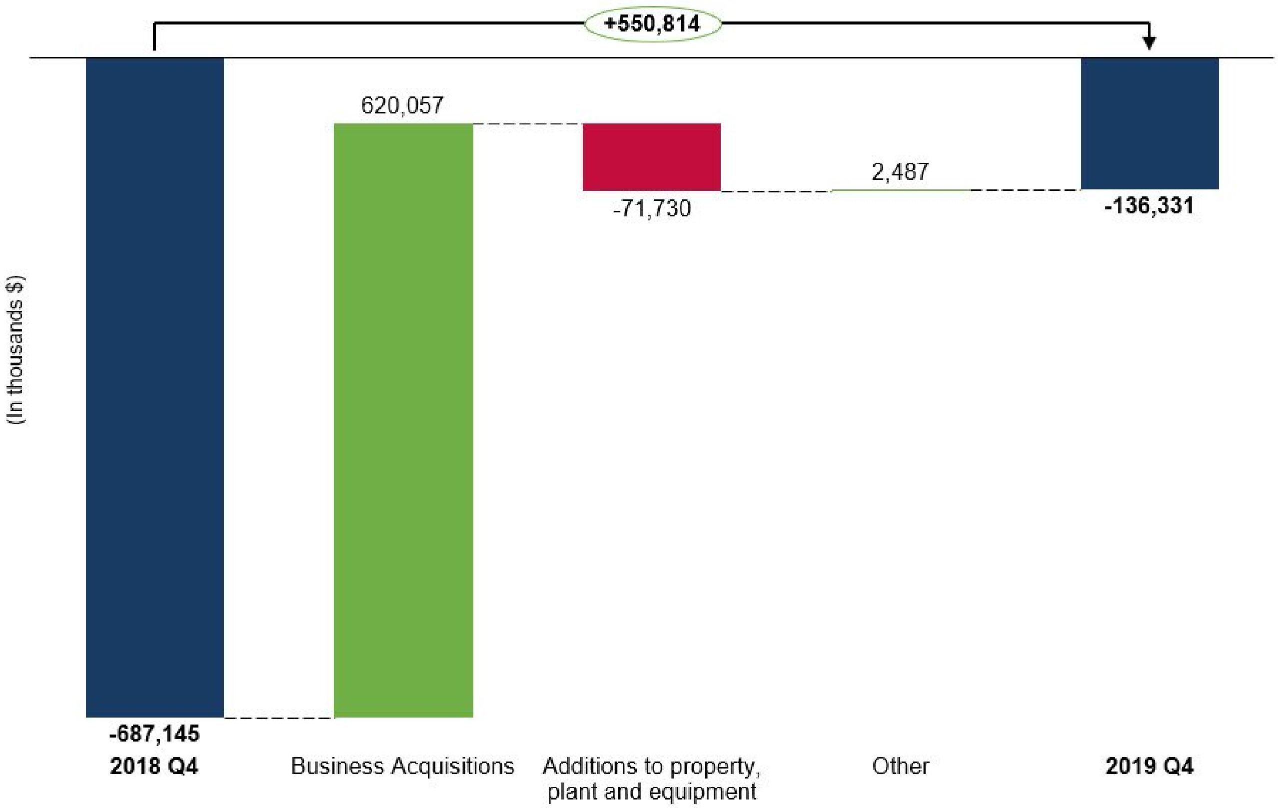
  The $363.1 million net increase in long-term loans and borrowings in 2019 is mainly attributable to:
  - a net increase of $405.9 million in Foard City project financing due to draws made on the construction and tax equity bridge loans as construction advanced in 2019, followed by repayment of the construction loan from the tax equity financing and the conversion of the bridge loans into a term loan; and
  - a net increase of $192.5 million in Phoebe project financing due to draws made on the Phoebe construction and tax equity bridge loans as construction advanced in 2019, followed by repayment of the construction loan from the tax equity financing and the conversion of the bridge loans into a term loan.

  The above increases related to long-term debt were partly offset by:
  - a $124.4 million net reimbursement of the revolving credit facility; and
  - scheduled repayments of project loans.
- a $15.3 million decrease from dividends paid on common shares mainly stemming from the issuance of 24,327,225 shares on February 6, 2018 related to the Alterra acquisition;
- a $13.3 million decrease related to the redemption of the 4.25% Convertible Debentures; and
- a $5.9 million decrease from the issuance of convertible debentures, totaling $137.2 million in 2019, net of financing fees, compared with $143.1 million for the same period in 2018.

Discontinued operations also contributed to increasing cash flows from financing activities by $11.7 million, from $8.4 million in 2018, to $20.1 million in 2019.

Cash Flows from Investing Activities from Continuing Operations

Outflow down $550.8 million to $136.3 million for the three-month period ended December 31, 2019
Outflow down $613.3 million to $517.0 million for the twelve-month period ended December 31, 2019



For the three-month period ended on December 31, 2019, compared with the same period last year

The decrease in cash outflows from investing activities from continuing operations is mainly related to:

- a decrease in cash outlays toward business acquisitions, from $620.1 million in 2018 to nil in 2019; and

These items were partly offset by:

- increased cash outflows related to property, plant and equipment of $71.7 million, from $72.4 million in 2018 to $144.1 million in 2019, related primarily to the acquisition of solar panels for the Hillcrest solar project and for other future solar projects.

Discontinued operations contributed to the decrease in cash outflows from investing activities by $11.4 million, from an outflow of $11.4 million in 2018 to nil in 2019.

For the twelve-month period ended on December 31, 2019, compared with the same period last year

The decrease in cash outflows from investing activities from continuing operations is mainly related to:

- a decrease in cash outlays toward business acquisitions, from $864.3 million in 2018 to nil in 2019;
- a $381.0 million cash inflow stemming from the US$297.9 million ($401.5 million) proceeds received from the sale of HS Orka, net of transaction costs and cash disposed; and
- a decrease in cash outlays toward investments in joint ventures, from $134.1 million in 2018 to $13.8 million in 2019. The outlay in 2019 relates to the payment of the remaining investment commitment into Energía Llaima.

These items were partly offset by:

- increased cash outflows towards additions to property, plant and equipment of $694.3 million, from $153.4 million in 2018 to $847.7 million in 2019, related primarily to the construction of the Phoebe solar and the Foard City wind facilities, and to the acquisition, during the fourth quarter, of solar panels for the Hillcrest solar project and for other future solar projects; and
- a $49.3 million unfavourable change in restricted cash balances, from a $34.4 million decrease in restricted cash in 2018, to a $14.9 million increase in restricted cash in 2019.

FREE CASH FLOW AND PAYOUT RATIO

Free Cash Flow and Payout Ratio calculation[1]	Trailing twelve months ended December 31		
	2019	2018	2017
Cash flows from operating activities	240,065	209,390	192,451
Add (Subtract) the following items:			
Changes in non-cash operating working capital items	(25,634)	11,019	(23,782)
Maintenance capital expenditures net of proceeds from disposals	(8,752)	(9,652)	(3,973)
Scheduled debt principal payments	(128,691)	(86,079)	(67,572)
Free Cash Flow attributed to non-controlling interests[2]	(12,679)	(27,984)	(10,425)
Dividends declared on Preferred shares	(5,942)	(5,942)	(5,942)
Add (subtract) the following non-recurring elements:			
Transaction costs related to realized acquisitions	266	8,280	6,450
Realized loss on termination of interest rate swaps	4,145	6,092	—
Realized loss on the Phoebe basis hedge[4]	11,697	—	—
Recovery of maintenance capital expenditures and prospective project expenses on sale of HS Orka, net of attribution to non-controlling interests [3]	8,242	—	—
Income tax paid on realized intercompany gain	10,594	—	—
Free Cash Flow	93,311	105,124	87,207
Dividends declared on common shares	95,046	90,215	71,621
Payout Ratio	102%	86%	82%
Adjust for the following items:			
Prospective projects expenses	12,905	16,719	19,574
Adjusted Free Cash Flow	106,216	121,843	106,781
Dividends declared on common shares - DRIP adjusted	93,422	80,497	67,990
Adjusted Payout Ratio	88%	66%	64%

1. Free Cash Flow, Adjusted Free Cash Flow, Payout Ratio and Adjusted Payout Ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.
2. The portion of Free Cash Flow attributed to non-controlling interests is subtracted, regardless of whether an actual distribution to non-controlling interests is made, in order to reflect the fact that such distributions may not occur in the period they are generated.
3. The sale of HS Orka has allowed for the recovery of maintenance capital expenditures and prospective project expenses incurred thereon since the acquisition of the project in February 2018, totaling $5.7 million and $9.6 million, respectively. An amount of $7.1 million was deducted from the total recovery as it pertains to non-controlling interests.
4. Due to their limited occurrence (over the remaining contractual period of 2 years), gains and losses on the Phoebe basis hedge are deemed not to represent the long-term cash generating capacity of Innergex.

Free Cash Flow

For the trailing twelve months ended December 31, 2019, the Corporation generated Free Cash Flow of $93.3 million, compared with $105.1 million for the corresponding period last year.

The decrease in Free Cash Flow is due mainly to:

- greater scheduled debt principal payments, mainly from the Innergex Cartier Energie project loan stemming from the acquisition of the Cartier Wind Farms during the fourth quarter of 2018, partly offset by the concurrent repayment of the Anse-à-Valleau, Carleton and Montagne-Sèche project loans;
- a decrease in cash flows from operating activities before changes in non-cash working capital items, including the contribution from the discontinued operations;

These items were partly offset by:

- a decrease in the Free Cash Flow attributed to non-controlling interests mainly related to the disposal of HS Orka, as well as below-average water flows in British Columbia affecting certain facilities containing non-controlling interests.

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

From these items were added back the following main non-recurring elements:

- an $11.7 million realized net loss on the Phoebe basis hedge (2018 - nil);
- the $10.6 million income tax paid toward the taxable gain realized following an intercompany transaction related to the Phoebe solar project concurrent with the initial funding; this transaction is deemed a cash outflow from investing activities (2018 - nil); and
- an $8.2 million recovery of maintenance capital expenditures and prospective project expenses, net of attribution to non-controlling interests (2018 - nil); and
- a $4.1 million realized loss on termination of interest rate swaps stemming from the Yonne project loan refinancing (2018 - $6.1 million realized loss on termination of interest rate swaps following project loans refinancing concurrent with the acquisition of the Cartier Wind Farms).

Payout Ratio

For the trailing twelve months ended December 31, 2019, the dividends on common shares declared by the Corporation amounted to 102% of Free Cash Flow, compared with 86% for the corresponding period last year.

This change results mainly from:

- higher dividend payments as a result of the issuance of 24,327,225 shares on February 6, 2018, related to the Alterra acquisition;
- an increase in the quarterly dividend;
- additional shares issued under the DRIP; and
- an $11.8 million decrease in Free Cash Flow as described above.

The Payout Ratio is a measure of the Corporation's ability to sustain current dividends and dividend increases as well as its ability to fund its growth. The Payout Ratio level reflects the Corporation's decision to invest yearly in advancing the development of its Prospective Projects, for which investments must be expensed as incurred. The Corporation considers such investments essential to its long-term growth and success, as it believes that the greenfield development of renewable energy projects offers the greatest potential internal rates of return and represents the most efficient use of management's expertise and value-added skills.

PROJECTED FINANCIAL PERFORMANCE

As at December 31, 2019, the Corporation had 68 Operating Facilities with a net installed capacity of 2,588 MW (gross 3,488 MW) and produced, on a consolidated basis, 6,510 GWh.

The increase in installed capacity and in the number of facilities in operation in 2019 is related to the two facilities that were commissioned in Texas. This increase was partly offset by the sale of the Corporation's participation in HS Orka, which owned two geothermal facilities.

In 2019, Power Generated was projected to increase 10%, Revenues were expected to increase 7%, Adjusted EBITDA was expected to increase 11% and Adjusted EBITDA Proportionate was expected to increase 15%. The actual increases were respectively 12%, 4%, 10% and 15%.

The Corporation makes projections using certain assumption to provide readers with an indication of its business activities and operating performance. For 2020, projections are based on continuing operations (HS Orka is excluded), the commissioning of Hillcrest solar project in the fourth quarter of 2020 and the interest saving due to the debt repayment following the private placement with Hydro-Québec. It does not take into consideration potential acquisitions that could be achieved in 2020.

In 2020, the Corporation expects power generated to increase 25%, Revenues to increase 10%, Adjusted EBITDA to increase 5% and Adjusted EBITDA Proportionate to increase 10%.

	2020		2019					2018	
	Continued operations[1]		Continued operations[1]	HS Orka	Total	Projected[2]	Actual	Total[3]	Actual
Production (GWh)	approx.	+25%	6,510	545	7,055	+10%	+12 %	6,283	+43%
Revenues	approx.	+10%	557,042	40,006	597,048	+7%	+4 %	576,616	+44%
Adjusted EBITDA	approx.	+5%	409,175	13,291	422,466	+11%	+10 %	385,081	+29%
Adjusted EBITDA Proportionate	approx.	+10%	516,819	13,291	530,110	+9%	+15 %	459,107	+49%
Number of facilities in operation	69				68			68	
Net installed capacity (MW)	2,788				2,588			2,082	

1. Projected financial performance based on the continued operations
2. As disclosed in the Press release issued on March 25, 2019
3. Including continued operations and HS Orka

With two large projects commissioned, Innergex achieved solid growth in 2019. Seven Development Projects were also advanced, two of which are currently under construction.

Looking ahead, we anticipate achieving commercial operation at the Hillcrest and Yonne II projects in 2020. We will also identify growth opportunities as part of the Strategic Alliance formed with Hydro-Québec on February 6, 2020. The Innergex team remains committed to seeking out strategic opportunities for acquisitions to gain a foothold in new markets as well as consolidate its position in regions where it already operates.

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

QUARTERLY FINANCIAL INFORMATION

(in millions of dollars, unless otherwise stated)	Three months ended Dec. 31, 2019	Sept. 30, 2019	June 30, 2019	March 31, 2019
Production (MWh)	1,793,803	1,665,362	1,741,953	1,308,505
Revenues	143.1	142.8	144.7	126.4
Adjusted EBITDA[1]	103.3	107.4	105.2	93.2
Net (loss) earnings	(47.4)	9.7	7.3	(0.9)
Net (loss) earnings from continuing operations attributable to owners of the parent	(46.8)	14.3	(7.8)	(7.4)
Net (loss) earnings from continuing operations attributable to owners of the parent ($ per share – basic and diluted)	(0.35)	0.10	(0.07)	(0.07)
Net (loss) earnings attributable to owners of the parent	(46.2)	14.1	10.8	(6.7)
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.35)	0.09	0.07	(0.06)
Dividends declared on common shares	24.4	23.9	23.4	23.4
Dividends declared on common shares, $ per share	0.175	0.175	0.175	0.175

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

(in millions of dollars, unless otherwise stated)	Three months ended Dec. 31, 2018	Sept. 30, 2018	June 30, 2018	March 31, 2018
Production (MWh)	1,396,066	1,236,722	1,509,599	944,108
Revenues	138.3	116.5	124.9	101.8
Adjusted EBITDA[1]	103.3	83.7	91.7	73.6
Net earnings (loss)	14.2	9.5	16.9	(14.8)
Net earnings (loss) from continuing operations attributable to owners of the parent	15.9	8.8	10.0	(2.9)
Net earnings (loss) from continuing operations attributable to owners of the parent ($ per share – basic and diluted)	0.12	0.06	0.06	(0.04)
Net earnings (loss) attributable to owners of the parent	13.7	10.7	13.3	(6.6)
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.10	0.07	0.09	(0.07)
Dividends declared on common shares	22.6	22.6	22.5	22.5
Dividends declared on common shares, $ per share	0.170	0.170	0.170	0.170

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

RELATED PARTY TRANSACTIONS

Related party transactions conducted in the normal course of operations are measured at fair value, which is the amount established and agreed to by the related parties, unless specific requirements within IFRS require different treatment.

As part of the acquisition of Alterra, the following debts were assumed: (i) in 2011, Ross J. Beaty, chairman of the board of directors and a large shareholder of Alterra, entered into a revolving credit facility with Alterra (the “Credit Facility”). The Credit Facility had a borrowing capacity of $20 million and made funds available to Alterra on a revolving basis at an interest rate of 8% per annum, compounded and payable monthly. In addition, a standby fee in the amount of 0.75% of the Credit Facility and a drawdown fee in the amount of 1.5% of amounts advanced were payable in cash. The Credit Facility matured on March 31, 2018. Alterra had borrowed $17.3 million under the Credit Facility; and (ii) in October 2016, Ross J. Beaty loaned, through a five-year term bond, US$35.7 million to Alterra’s subsidiary Magma Energy Sweden A.B (the “Bond”). The Bond paid interest at 8.5% per annum with an upfront fee of 2% of the principal, which was paid at closing of the financing. The Bond was collateralized by 15% of the outstanding shares in HS Orka. To optimize its treasury management, the Corporation repaid both the Credit Facility and the Bond in the first quarter of 2018.

NON-IFRS MEASURES

This MD&A has been prepared in accordance with IFRS. However, some measures referred to in this MD&A are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Innergex believes these indicators are important, as they provide management and the reader with additional information about the Corporation's production and cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods. Innergex's share of Revenues of joint ventures and associates, Revenues Proportionate, Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted EBITDA Proportionate, Innergex's share of Adjusted EBITDA of joint ventures and associates, Adjusted Net (Loss) Earnings from continuing operations, Free Cash Flow, Adjusted Free Cash Flow, Payout Ratio and Adjusted Payout Ratio are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS.

Revenues Proportionate

References in this document to "Innergex's share of Revenues of joint ventures and associates" are to Innergex's equity interest in the joint ventures and associates' Revenues. Readers are cautioned that Innergex's share of Revenues of joint ventures and associates should not be construed as an alternative to Revenues, as determined in accordance with IFRS.

References in this document to "Revenues Proportionate" are to Revenues plus Innergex's share of Revenues of the joint ventures and associates. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Revenues Proportionate should not be construed as an alternative to Revenues, as determined in accordance with IFRS. Please refer to the "Operating Results" section for more information.

	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Revenues	143,116	138,252	557,042	481,418
Innergex's share of Revenues of joint ventures and associates:				
Toba Montrose (40%) [1]	3,087	2,911	28,257	26,174
Shannon (50%) [1]	4,071	2,134	9,629	6,967
Flat Top (51%) [2]	6,142	2,550	12,447	7,679
Dokie (25.5%) [2]	3,832	3,382	9,297	8,061
Jimmie Creek (50.99%) [2]	955	1,208	10,929	9,775
Umbata Falls (49%)	1,256	1,681	4,029	4,635
Viger-Denonville (50%)	1,472	1,663	5,647	5,862
Duqueco (50%) [3,5]	5,036	6,896	19,535	12,019
Guayacán (50%) [3,5]	532	890	2,011	1,213
Pampa Elvira (50%) [3,5]	612	471	2,118	883
	26,995	23,786	103,899	83,268
Revenues Proportionate	170,111	162,038	660,941	564,686

1. For a complete three-month period in 2019 and 2018 and for the period from January 1, 2019, to December 31, 2019, and February 6, 2018, to December 31, 2018.
2. For a complete three-month period in 2019 and 2018 and for the period from January 1, 2019, to December 31, 2019, and March 23, 2018, to December 31, 2018.
3. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and the Pampa Elvira (55% interest) facilities and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.
4. For a complete three-month period in 2019 and 2018 and for the period from January 1, 2019, to December 31, 2019, and for the period from July 3, 2018, or July 5, 2018, to December 31, 2018.

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

Adjusted EBITDA and Adjusted EBITDA Margin

References in this document to “Adjusted EBITDA” are to net earnings (loss) from continuing operations, to which are added (deducted) provision (recovery) for income tax expenses, finance cost, depreciation and amortization, other net (revenues) expenses, share of (earnings) loss of joint ventures and associates and unrealized net (gain) loss on financial instruments. Other net revenues related to PTCs are included in Adjusted EBITDA. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted EBITDA should not be construed as an alternative to net earnings, as determined in accordance with IFRS.

References in this document to "Adjusted EBITDA Margin" are to Adjusted EBITDA divided by revenues. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance.

	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Net (loss) earnings from continuing operations	(48,049)	18,816	(53,026)	26,215
Provision for income taxes	117,687	26,666	118,851	27,245
Finance costs	61,062	55,020	231,766	195,834
Depreciation and amortization	53,021	42,285	194,579	151,256
Impairment of project development costs	8,184	—	8,184	—
EBITDA	191,905	142,787	500,354	400,550
Other net (revenues) expenses	(102,004)	6,864	(104,643)	12,183
Share of earnings of joint ventures and associates	(27,276)	(37,320)	(36,469)	(47,596)
Unrealized net loss (gain) on financial instruments	40,708	(9,061)	49,933	(12,958)
Adjusted EBITDA	103,333	103,270	409,175	352,179
Adjusted EBITDA margin	72.2%	74.7%	73.5%	73.2%

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

Adjusted EBITDA Proportionate

References in this document to "Innergex's share of Adjusted EBITDA of the joint ventures and associates" are to Innergex's equity interest in the joint ventures and associates' Adjusted EBITDA.

References in this document to "Adjusted EBITDA Proportionate" are to Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the operating joint ventures and associates, other revenues related to PTCs, and Innergex's share of the operating joint ventures and associates' other revenues related to PTCs. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted EBITDA Proportionate should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section of this MD&A for more information.

During the year ended December 31, 2019, upon commissioning the Foard City wind project, the Adjusted EBITDA Proportionate measure was changed to reflect PTC generation from the Corporation' wind facilities and from its joint ventures and associates' wind facilities. PTCs represent an important factor to a U.S. wind project's financial performance and have been a major driver to determining their economic feasibility. PTCs are currently used, in most part, as an element of the principal repayment of the Corporation's tax equity financing.

	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Adjusted EBITDA	103,333	103,270	409,175	352,179
Innergex's share of Adjusted EBITDA of joint ventures and associates:				
Toba Montrose (40%) [1]	1,667	1,326	21,713	20,209
Shannon (50%) [2]	2,992	985	4,229	2,804
Flat Top (51%) [2]	5,094	894	5,805	2,707
Dokie (25.5%) [1]	3,221	2,804	7,020	6,109
Jimmie Creek (50.99%) [1]	383	747	8,661	8,142
Umbata Falls (49%)	1,056	1,559	3,234	4,189
Viger-Denonville (50%)	1,147	1,389	4,565	4,834
Duqueco (50%) [3,4]	3,901	4,894	13,016	8,027
Guayacán (50%) [3,4]	365	557	1,387	595
Pampa Elvira (50%) [3,4]	289	(182)	954	(244)
	20,115	14,973	70,584	57,372
PTCs and Innergex's share of PTCs generated:				
Foard City	11,238	—	11,238	—
Shannon (50%) [1]	3,017	2,546	11,323	9,657
Flat Top (51%) [2]	3,581	3,291	14,499	9,476
	17,836	5,837	37,060	19,133
Adjusted EBITDA Proportionate	141,284	124,080	516,819	428,684

1. For a complete three-month period in 2019 and 2018 and for the period from January 1, 2019, to December 31, 2019, and February 6, 2018, to December 31, 2018.
2. For a complete three-month period in 2019 and 2018 and for the period from January 1, 2019, to December 31, 2019, and March 23, 2018, to December 31, 2018.
3. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and the Pampa Elvira (55% interest) facilities, and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.
4. For a complete three-month period in 2019 and 2018 and for the period from January 1, 2019, to December 31, 2019, and for the period from July 3, 2018, or July 5, 2018, to December 31, 2018

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

Adjusted Net (Loss) Earnings from continuing operations

References to "Adjusted Net (Loss) Earnings from continuing operations" are to net earnings or losses from continuing operations of the Corporation, to which the following elements are added (subtracted): unrealized net (gain) loss on financial instruments; realized (gain) loss on financial instruments; income tax expense (recovery) related to the above items; and the share of unrealized net (gain) loss on derivative financial instruments of joint ventures and associates, net of related tax. Innergex uses derivative financial instruments to hedge its exposure to various risks. Accounting for derivatives under IFRS requires that all derivatives are marked-to-market with changes in the mark-to-market of the derivatives for which hedge accounting is not applied, being taken to the profit and loss account. The application of this accounting standard results in a significant amount of profit and loss volatility arising from the use of derivatives that are not designated for hedge accounting. The Adjusted Net (Loss) Earnings from continuing operations of the Corporation aims to eliminate the impact of the mark-to-market rules on derivatives on the profit and loss of the Corporation. Innergex believes the analysis and presentation of net earnings or loss on this basis enhances understanding of the Corporation's operating performance. Readers are cautioned that Adjusted Net (Loss) Earnings from continuing operations should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section for reconciliation of the Adjusted Net (Loss) Earnings from continuing operations.

Free Cash Flow and Payout Ratio

References to “Free Cash Flow” are to cash flows from operating activities before changes in non-cash operating working capital items, less maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends declared and the portion of Free Cash Flow attributed to non-controlling interests, plus or minus other elements that are not representative of the Corporation's long-term cash generating capacity, such as transaction costs related to realized acquisitions (which are financed at the time of the acquisition), realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt or the exchange rate on equipment purchases. Innergex believes that presentation of this measure enhances the understanding of the Corporation's cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. Readers are cautioned that Free Cash Flow should not be construed as an alternative to cash flows from operating activities, as determined in accordance with IFRS. Please refer to the "Free Cash Flow and Payout Ratio" section for the reconciliation of Free Cash Flow.

References to "Adjusted Free Cash Flow" are to Free Cash Flow excluding prospective project expenses and non-recurring items.

References to “Payout Ratio” are to dividends declared on common shares divided by Free Cash Flow. Innergex believes that this is a measure of its ability to sustain current dividends and dividend increases as well as its ability to fund its growth.

References to "Adjusted Payout Ratio" are to dividends declared on common shares divided by Adjusted Free Cash Flow after the impact of the DRIP.

Production KPIs

Production Proportionate

References in this document to "Innergex's share of Production of the joint ventures and associates" are to Innergex's equity interest in the joint ventures and associates' Production.

References in this document to "Production Proportionate" are to Production plus Innergex's share of Production of the joint ventures and associates. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Please refer to the "Operating Results" section of this MD&A for more information.

	Three months ended December 31					
	2019			2018		
(in MWh)	Production (MWh)	LTA (MWh)	Production as a % of LTA	Production (MWh)	LTA (MWh)	Production as a % of LTA
Production	1,793,803	1,935,082	93%	1,396,066	1,399,745	100%
Innergex's share of Production of joint ventures and associates:						
Toba Montrose (40%)	25,902	31,318	83%	24,279	31,318	78%
Shannon (50%)	91,956	92,696	99%	82,718	92,696	89%
Flat Top (51%)	109,055	117,260	93%	106,859	117,260	91%
Dokie (25.5%)	30,923	22,814	136%	26,301	22,814	115%
Jimmie Creek (50.99%)	5,659	6,854	83%	7,135	6,854	104%
Umbata Falls (49%)	16,656	16,188	103%	22,306	16,188	138%
Viger-Denonville (50%)	9,740	10,150	96%	11,058	10,150	109%
Duqueco (50%) [1]	52,591	58,081	91%	69,692	58,081	120%
Guayacán (50%) [1]	6,212	7,530	82%	8,155	7,530	108%
Pampa Elvira (50%) [1]	3,302	3,685	90%	3,203	3,685	87%
	351,996	366,576	96%	361,706	366,576	99%
Production Proportionate	2,145,799	2,301,658	93%	1,757,772	1,766,321	100%

1. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and Pampa Elvira (55% interest) facilities, and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.

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

(in MWh)	Year ended December 31					
	2019			2018		
	Production (MWh)	LTA (MWh)	Production as a % of LTA	Production (MWh)	LTA (MWh)	Production as a % of LTA
Production	6,509,622	6,770,170	96 %	5,086,497	5,283,616	96 %
Innergex's share of Production of joint ventures and associates:						
Toba Montrose (40%) [1]	269,684	285,545	94 %	262,318	281,678	93 %
Shannon (50%) [1]	344,892	356,903	97 %	308,911	323,319	96 %
Flat Top (51%) [2]	441,528	444,975	99 %	312,408	339,956	92 %
Dokie (25.5%) [1]	75,723	77,261	98 %	68,702	67,363	102 %
Jimmie Creek (50.99%) [2]	93,603	84,904	110 %	88,504	84,594	105 %
Umbata Falls (49%)	53,291	53,459	100 %	59,498	53,459	111 %
Viger-Denonville (50%)	37,366	36,200	103 %	38,981	36,200	108 %
Duqueco (50%) [3,4]	161,752	166,525	97 %	117,270	111,850	105 %
Guayacán (50%) [3,4]	21,197	23,688	89 %	12,145	11,786	103 %
Pampa Elvira (50%) [3,4]	13,100	14,398	91 %	6,499	7,238	90 %
	1,512,136	1,543,858	98 %	1,275,236	1,317,443	97 %
Production Proportionate	8,021,758	8,314,028	96 %	6,361,733	6,601,059	96 %

1. For the period from January 1, 2019, to December 31, 2019, and February 6, 2018, to December 31, 2018.
2. For the period from January 1, 2019, to December 31, 2019, and March 23, 2018, to December 31, 2018.
3. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and Pampa Elvira (55% interest) facilities, and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.
4. For the period from January 1, 2019 to December 31, 2019 and for the period from July 3, 2018 or July 5, 2018 to December 31, 2018.

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

FORWARD-LOOKING INFORMATION

To inform readers of the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws (“Forward-Looking Information”), including the Corporation's power production, prospective projects, successful development, construction and financing (including tax equity funding) of the projects under construction and the advanced-stage prospective projects, sources and impact of funding, project acquisitions, execution of non-recourse project-level financing (including the timing and amount thereof), and strategic, operational and financial benefits and accretion expected to result from such acquisitions, business strategy, future development and growth prospects (including expected growth opportunities under the Strategic Alliance), business integration, governance, business outlook, objectives, plans and strategic priorities, and other statements that are not historical facts. Forward-Looking Information can generally be identified by the use of words such as “approximately”, “may”, “will”, "could", “believes", “expects", “intends”, "should", "would", “plans”, “potential”, "project", “anticipates”, “estimates”, “scheduled” or “forecasts”, or other comparable terms that state that certain events will or will not occur. It represents the projections and expectations of the Corporation relating to future events or results as of the date of this MD&A.

Future-oriented financial information: Forward-Looking Information includes future-oriented financial information or financial outlook within the meaning of securities laws, including information regarding the Corporation's expected production, the estimated project costs, projected revenues, projected Adjusted EBITDA and projected Adjusted EBITDA Proportionate, Projected Free Cash Flow and intention to pay dividend quarterly, the estimated project size, costs and schedule, including obtainment of permits, start of construction, work conducted and start of commercial operation for Development Projects and Prospective Projects, The Corporation's intent to submit projects under Requests for Proposals, the qualification of U.S. projects for PTCs and ITCs and other statements that are not historical facts. Such information is intended to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of the potential financial impact of completed and future acquisitions and of the Corporation's ability to sustain current dividends and to fund its growth. Such information may not be appropriate for other purposes.

Assumptions: Forward-Looking Information is based on certain key assumptions made by the Corporation, including, without restriction, those concerning hydrology, wind regimes and solar irradiation, performance of operating facilities, project performance, economic, financial and financial market conditions, the Corporation’s success in developing and constructing new facilities, expectations and assumptions concerning availability of capital resources and timely performance by third parties of contractual obligations and receipt of regulatory approvals.

Risks and Uncertainties: Forward-Looking Information involves risks and uncertainties that may cause actual results or performance to be materially different from those expressed, implied or presented by the Forward-Looking Information. These are referred to in the "Risks and Uncertainties" section of the Annual Report and include, without limitation: the ability of the Corporation to execute its strategy for building shareholder value; its ability to raise additional capital and the state of the capital markets; liquidity risks related to derivative financial instruments; variability in hydrology, wind regimes and solar irradiation; delays and cost overruns in the design and construction of projects; the ability to secure new power purchase agreements or renew any power purchase agreement; fluctuations affecting prospective power prices; health, safety and environmental risks; uncertainties surrounding the development of new facilities; obtainment of permits; equipment failure or unexpected operations and maintenance activity; interest rate fluctuations and refinancing risk; financial leverage and restrictive covenants governing current and future indebtedness; the possibility that the Corporation may not declare or pay a dividend; failure to realize the anticipated benefits of acquisitions; integration of the completed and future acquisitions; changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; variability of installation performance and related penalties; the ability to attract new talent or to retain officers or key employees; litigation; performance of major counterparties; social acceptance of renewable energy projects; relationships with stakeholders; equipment supply; exposure to many different forms of taxation in various jurisdictions; changes in general economic conditions; regulatory and political risks; ability to secure appropriate land; reliance on PPAs; availability and reliability of transmission systems (including due to reliance on third parties); foreign market growth and development risks; foreign exchange fluctuations; increases in water rental cost or changes to regulations applicable to water use; assessment of water, wind and solar resources and associated electricity production; global climate change; natural disasters and force majeure; cybersecurity; sufficiency of insurance coverage; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; reliance on shared transmission and interconnection infrastructure; the fact that revenues from certain facilities will vary based on the market (or spot) price of electricity; risks related to U.S. production and investment tax credits; changes in U.S. corporate tax rates and availability of tax equity financing; host country economic, social and political conditions; risk inherent to rockslides, avalanches, tornadoes, hurricanes or other occurrences outside the Corporation’s control; adverse claims to property title; unknown liabilities; reliance on intellectual property and confidential agreements to protect our rights and confidential information; and reputational risks arising from misconduct of representatives of the Corporation.

Although the Corporation believes that the expectations and assumptions on which Forward-Looking Information is based are reasonable under the current circumstances, readers are cautioned not to rely unduly on this Forward-Looking Information, as no assurance can be given that it will prove to be correct. Forward-Looking Information contained herein is provided as at the date of this MD&A, and the Corporation does not undertake any obligation to update or revise any Forward-Looking Information, whether as a result of events or circumstances occurring after the date hereof, unless so required by law.

Forward-Looking Information in this MD&A

The following table outlines the Forward-Looking Information contained in this MD&A, which the Corporation considers important to better inform readers about its potential financial performance, together with the principal assumptions used to derive this information and the principal risks and uncertainties that could cause actual results to differ materially from this information.

	Principal Risks and Uncertainties
Expected production For each facility, the Corporation determines a long-term average annual level of electricity production ("LTA") over the expected life of the facility, based on engineers' studies that take into consideration a number of important factors: for hydroelectricity, the historically observed flows of the river, the operating head, the technology employed and the reserved aesthetic and ecological flows; for wind energy, the historical wind and meteorological conditions and turbine technology; and for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation. Other factors considered include, without limitation, site topography, installed capacity, energy losses, operational features and maintenance. Although production will fluctuate from year to year, over an extended period it should approach the estimated LTA. On a consolidated basis, the Corporation estimates its LTA by adding together the expected LTAs of all the Operating Facilities that it consolidates. This consolidation excludes however the facilities which are accounted for using the equity method.	Improper assessment of water, wind and solar resources and associated electricity production Variability in hydrology, wind regimes and solar irradiation resources Equipment supply risk, including failure or unexpected operations and maintenance activity Natural disasters and force majeure Regulatory and political risks affecting production Health, safety and environmental risks affecting production Variability of installation performance and related penalties Availability and reliability of transmission systems Litigation
Projected revenues For each facility, expected annual revenues are estimated by multiplying the LTA by a price for electricity stipulated in the PPA secured with a public utility or other creditworthy counterparty. In most cases, these PPAs stipulate a base price for electricity produced and, in some cases, a price adjustment depending on the month, day and hour of its delivery. This excludes facilities that receive revenues based on the market (or spot) price for electricity, including the Foard City, Shannon and Flat Top wind farms, the Phoebe solar farm and the Miller Creek hydroelectric facility, which receives a price based on a formula using the Platts Mid-C pricing indices; and the Horseshoe Bend hydroelectric facility, for which 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission. In most cases, PPAs also contain an annual inflation adjustment based on a portion of the Consumer Price Index. On a consolidated basis, the Corporation estimates annual revenues by adding together the projected revenues of the Operating Facilities that it consolidates. The consolidation excludes however the facilities which are accounted for using the equity method.	See principal assumptions, risks and uncertainties identified under "Expected Production" Reliance on PPAs Revenues from certain facilities will vary based on the market (or spot) price of electricity Fluctuations affecting prospective power prices Changes in general economic conditions Ability to secure new PPAs or renew any PPA
Projected Adjusted EBITDA For each facility, the Corporation estimates annual operating earnings by adding (deducting) to net earnings (loss) provision (recovery) for income tax expenses, finance cost, depreciation and amortization, other net expenses, share of (earnings) loss of joint ventures and associates and unrealized net (gain) loss on financial instruments.	See principal assumptions, risks and uncertainties identified under "Expected Production" and "Projected Revenues" Unexpected maintenance expenditures
Projected Adjusted EBITDA Proportionate On a consolidated basis, the Corporation estimates annual Adjusted EBITDA Proportionate by adding to the projected Adjusted EBITDA Innergex's share of Adjusted EBITDA of the operating joint ventures and associates, other revenues related to PTCs, and Innergex's share of the other net revenues of the operating joint ventures and associates' related to PTCs.	See principal assumptions, risks and uncertainties identified under "Expected Production", "Projected Revenues" and "Projected Adjusted EBITDA"

	Principal Risks and Uncertainties
Intention to pay dividend quarterly The Corporation estimates the annual dividend it intends to distribute based on the Corporation's operating results, cash flows, financial conditions, debt covenants, long-term growth prospects, solvency, test imposed under corporate law for declaration of dividends and other relevant factors.	See principal assumptions, risks and uncertainties identified under "Expected Production", "Projected Revenues" and "Projected Adjusted EBITDA". Possibility that the Corporation may not declare or pay a dividend
Estimated project costs, expected obtainment of permits, start of construction, work conducted and start of commercial operation for Development Projects or Prospective Projects For each Development Project and Prospective Project, the Corporation may provide (where available) an estimate of potential installed capacity, estimated project costs, project financing terms and each project's development and construction schedule, based on its extensive experience as a developer, in addition to information directly related to incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for the projected costs and construction schedule provided by the engineering, procurement and construction ("EPC") contractor retained for the project. The Corporation provides indications based on assumptions regarding its current strategic positioning and competitive outlook, as well as scheduling and construction progress, for its Development Projects and its Prospective Projects, which the Corporation evaluates based on its experience as a developer.	Uncertainties surrounding development of new facilities Performance of major counterparties, such as suppliers or contractors Delays and cost overruns in the design and construction of projects Ability to secure appropriate land Obtainment of permits Health, safety and environmental risks Ability to secure new PPAs or renew any PPA Higher-than-expected inflation Equipment supply Interest rate fluctuations and financing risk Risks related to U.S. PTCs and ITCs, changes in U.S. corporate tax rates and availability of tax equity financing Regulatory and political risks Natural disaster and force majeure Relationships with stakeholders Foreign market growth and development risks Outcome of insurance claims Social acceptance of renewable energy projects Ability of the Corporation to execute its strategy of building shareholder value Failure to realize the anticipated benefits of completed and future acquisitions Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers
Intention to respond to requests for proposals The Corporation provides indications of its intention to submit proposals in response to requests for proposals ("Request for Proposals" or "RFP") based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these RFPs.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers Social acceptance of renewable energy projects Relationships with stakeholders

Qualification for PTCs and ITC and expected tax equity investment Flip Point For certain Development Projects in the United States, the Corporation has conducted on- and off-site activities expected to qualify its Development Projects for PTCs or ITC at the full rate and to obtain tax equity financing on such a basis. To assess the potential qualification of a project, the Corporation takes into account the construction work performed and the timing of such work. The expected Tax Equity Flip Point for tax equity investment is determined according to the LTAs and revenues of each such project and is subject in addition to the related risks mentioned above.	Risks related to U.S. PTCs and ITC, changes in U.S. corporate tax rates and availability of tax equity financing Regulatory and political risks Delays and cost overruns in the design and construction of projects Obtainment of permits

RISKS AND UNCERTAINTIES

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

Ability of the Corporation to Execute its Strategy for Building Shareholder Value
The Corporation's strategy for building shareholder value is to acquire or develop high-quality renewable power production facilities that generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital, and to distribute a stable dividend. However, there is no certainty that the Corporation will be able to acquire or develop high-quality renewable power production facilities at attractive prices to supplement its growth. Furthermore, this strategy may require the divestiture by the Corporation of certain assets, to pursue new opportunities, to support or realise the benefits of completed or future acquisitions, raise additional capital and/or lower the debts of the Corporation.

The successful execution of this strategy requires careful timing and business judgment, the resources to complete the development of power generating facilities, as well as an accurate assessment of the assets of the Corporation and the value that it would receive in exchange for their divestiture. The Corporation may underestimate the costs necessary to bring power generating facilities into commercial operation, may be unable to quickly and efficiently integrate new acquisitions into its existing operations, inaccurately evaluate the value of its assets or be unable to find a purchaser therefore in a manner which timely supports the Corporation's strategy.

Ability to Raise Additional Capital and the State of the Capital Market
Future development and construction of new facilities, the development of the Development Projects and the Prospective Projects and other capital expenditures will be financed by the Corporation out of cash generated from its Operating Facilities, borrowing or the issuance and sale 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 or future facilities would be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion. There are numerous renewable energy projects to be constructed in the coming years that will result in competition for capital. In addition, payment of dividends may impair the Corporation's ability to finance its ongoing and future projects.

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

Liquidity Risks Related to Derivative Financial Instruments
Derivative financial instruments are entered into with major financial institutions and their effectiveness is dependent on the performance of these institutions. Failure by one of them to perform its obligations could involve a liquidity risk. Liquidity risks related to derivative financial instruments also include the settlement of bond forward contracts on their maturity dates and the early termination option included in some interest rate swap contracts and foreign exchange contracts.

The occurrence of any of the foregoing could have a material adverse effect on the Corporation's business, financial condition and results of operations. The Corporation uses derivative financial instruments to manage its exposure to the risk of an increase in interest rates on its debt financing, of foreign currency variation or of electricity market price variation. The Corporation does not own or issue financial instruments for speculation purposes.

The nature of the Corporation's energy and risk management activities creates exposure to financial risks, which include, but are not limited to: (i) unfavourable movements in commodity prices, interest rates or foreign exchange which could result in a financial or opportunity loss to the Corporation; (ii) a lack of counterparties, due to market conditions or other circumstances, could leave the Corporation unable to liquidate or offset a position, or unable to do so at or near the previous market price; (iii) the Corporation may not receive funds or instruments from counterparties at the expected time or at all; (iv) the counterparty could fail to perform an obligation owed to the Corporation; (v) loss as a result of human error or deficiency in the Corporation's systems or controls; and (vi) loss as a result of contracts being unenforceable or transactions being inadequately documented.

Variability in Hydrology, Wind Regimes and Solar Irradiation
The amount of energy generated by the Corporation's hydroelectric facilities depends on the availability of water flows. There is no certainty that the long-term availability of such resources will remain unchanged. 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 farms will depend upon the availability of wind, which is naturally variable. A reduced or increased amount of wind at the location of one of the wind farms 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 farms will depend on the availability of solar radiation, which is naturally variable. Lower solar irradiation levels at the Corporation's solar farms over an extended period may reduce the production from such facilities and the Corporation's revenues and profitability. Variability in hydrology, wind regimes and solar irradiation and their predictability may also be affected by climate changes which may provoke unforeseen changes in the historical trends.

Delays and Cost Overruns in the Design and Construction of Projects
Delays and cost overruns may occur in completing the construction of the Development Projects and the development and construction of Prospective Projects and future projects that the Corporation will undertake. A number of factors which could cause such delays or cost over-runs include, without limitation, 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 period of warranty has expired, resulting in loss of production as well as the cost of repair. In addition, if the Development Projects are not brought into commercial operation within the delay stipulated in their PPA, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related PPA.

Ability to Secure New Power Purchase Agreements or Renew Any Power Purchase Agreement
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 various forms of PPAs (corporate or utility owned) for the sale of its power, which PPAs are mainly obtained through participation in competitive Requests for Proposals processes or bilateral negotiations. During these processes and negotiations, 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, that the Corporation will be successful in such negotiations or that existing PPAs will be renewed or will be renewed on equivalent terms and conditions upon the expiry of their respective terms.

Fluctuations Affecting Prospective Power Prices
If the Corporation is unable to secure or renew PPAs for its development assets or maintain or renew PPAs for its producing assets or contracts for the sale of 100% of generation, the Corporation may be forced to sell electrical power generated at market price. Although, most of the output at the Shannon Wind Farm, the Flat Top Wind Farm, Foard CIty Wind Farm and the Phoebe Solar Farm are sold under long-term PPAs, output not sold under the long-term power hedge agreement is and will be subject to merchant prices. If the Corporation is unable to produce enough power to meet its contractual obligations under its PPAs, the Corporation will be forced to purchase third-party power at merchant prices. If the settlement point of the Corporation's long-term power hedge agreements (a form of PPA) differs from the point of interconnection, power sales pursuant to that power hedge are further subject to locational risk. This potential difference in pricing is referred to as a "basis differential". Depending on the specifics of the power hedge, a large basis differential could require the Corporation to purchase third-party power at merchant prices, or otherwise supplement the basis differential to the hedge provider. Power sales under power hedges are also required to be sold in blocks of hourly periods. If the Corporation's output within any given block is insufficient to meet its contractual commitments, it may be required to purchase third party power at merchant prices to meet its commitments. This potential risk is referred to as a "shape risk".

The market price of power in individual jurisdictions can be volatile and may be incapable of being controlled. If the price of electricity should drop significantly, in each of the cases described above, the economic prospects of the operating facilities that rely, in whole or in part, on merchant prices, such as the Shannon Wind Farm, the Flat Top Wind Farm, the Phoebe Solar

Farm, the Miller Creek Facility or development projects in which the Corporation has an interest, could be significantly reduced or rendered uneconomic. A material reduction in such prices, or a non-material reduction in such prices coupled with the impact of the aggregate risks described above, could have a material adverse effect on the Corporation's financial condition, in particular, with respect to the Shannon Wind Farm.

Health, Safety and Environmental Risks
The ownership, construction 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, licences, permits and other approvals, and potential civil liability. Compliance with health, safety and environmental laws (and any future changes) and the requirements of licences, permits and other approvals, such as sound level and other operational restrictions, 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 licences, 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, licences, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures. Consequently, 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.

Uncertainties Surrounding Development of New Facilities
The Corporation participates in the construction and development of new power generating facilities. These facilities have greater uncertainty surrounding their feasibility, social acceptance and future profitability than existing Operating Facilities with established track records. In certain cases, many factors affecting costs are not yet determined, such as land royalty payments, water royalties, or municipal or other applicable taxes. The Corporation is in some cases required to advance funds and post-performance bonds during development of its new facilities. If some of these facilities are not completed or do not operate to the expected specifications, or unforeseen costs or taxes are incurred, the Corporation could be adversely affected.

Obtainment of Permits
The Corporation does not currently hold all the approvals, licences 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 licences, 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 or commenced. There can be no assurance that any one Prospective Project will result in any actual operating facility.

In addition, delays may occur in obtaining necessary government approvals required for future power projects.

From time to time, and to secure long lead times required for ordering equipment, the Corporation may place orders for equipment and make deposits thereon or advance projects prior to obtaining all requisite permits and licences. The Corporation only takes such actions where it reasonably believes that such licences or permits will be forthcoming in due course prior to the requirement to expend the full amount of the purchase price. However, any delay in permitting could adversely affect the Corporation.

Environmental permits to be issued regarding any of the Development Projects or the Prospective Projects may contain conditions that need to be satisfied prior to obtaining a PPA, to start construction, during construction and during and after the operation of the Development Projects. It is not possible to predict the conditions imposed by such permits or the cost of any mitigating measures required by such permits.

Equipment Failure or Unexpected Operations and Maintenance Activity
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 down times 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 Fluctuations 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. Interest rate fluctuation and refinancing risks could affect the Corporation's ability to raise additional capital.

Financial Leverage and Restrictive Covenants Governing Current and Future Indebtedness
The Corporation's and its subsidiaries' operations 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, equity finance and security agreements. These restrictions prohibit or limit the Corporation's and its subsidiaries' ability to, among other things, incur additional debt, provide guarantees for indebtedness, create liens, dispose of assets, liquidate, dissolve, amalgamate, consolidate or effect any corporate or capital reorganization, make distributions or pay dividends, issue any equity interests and create subsidiaries. These restrictions may limit the Corporation's and its subsidiaries' ability to obtain additional financing, withstand downturns in 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 or equity financing on terms that include more restrictive covenants, require repayment on an accelerated schedule or impose other obligations that limit the Corporation's or its subsidiaries' ability to grow the business, acquire assets or take other actions the Corporation or its subsidiaries might otherwise consider appropriate or desirable.

Possibility that the Corporation May Not Declare or Pay a Dividend
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 Corporation does not face any restrictions that would prevent it from paying out dividends or distributions. As of the date of this MD&A, the Corporation does not expect to make any changes to its dividend policy. However, the declaration of dividends is at the discretion of the Board of Directors even if the Corporation has enough funds, net of its liabilities, to pay such dividends.

The Corporation may not declare or pay a dividend if the Corporations' cash available for distribution is not sufficient or 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. No assurance can be given as to whether the Corporation will in the future pay dividends, or the frequency or amounts of any such dividends.

Failure to Realize the Anticipated Benefits of Completed and Future Acquisitions
The Corporation believes that completed and future acquisitions will provide benefits for the Corporation. However, there is a risk that some or all the expected benefits will fail to materialize or may not occur within the time periods anticipated by the management of the Corporation. The realization of such benefits may be affected by many factors, many of which are beyond the control of the Corporation.

Integration of the Completed and Future Acquisitions
The integration of completed and future business and/or project acquisitions and their respective activities, employees and officers, operations and facilities may result in significant challenges and management of the Corporation may be unable to accomplish the integration successfully or without spending significant amounts of money or other resources. For completed and future acquisitions, there can be no assurance that Management will be able to successfully integrate the teams, activities and facilities forming part of such acquisitions or fully realize the expected benefits of such acquisitions.

Changes in Governmental Support to Increase Electricity to be Generated from Renewable Sources by Independent Power Producers
Development and growth of renewable energy is dependent on governmental support, policies and incentives. Many governments have introduced portfolio standards, tax credits and other incentives to increase the portion of renewable energy in their electricity generation supply mix to reduce greenhouse gas emissions over time. There is a risk that governmental support providing incentives for renewable energy could change at any time and that additional increase in the procurement of renewable energy projects from independent power producers be reduced or suspended at any time. As a result, the Corporation may face reduced ability to develop its prospective projects and may suffer material write-offs of prospective projects.

Variability of Installation Performance and Related Penalties
The ability of the Corporation's facilities to generate the maximum amount of power which can be sold to Hydro-Québec, BC Hydro, the IESO, Électricité de France and 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 the revenues and profitability of the Corporation.

Ability to Attract New Talent or to Retain Officers or Key Employees

The Corporation's officers and other key employees play a significant role in the Corporation's success. The conduct of the Corporation's business and the execution of the Corporation's growth strategy rely heavily on teamwork and the Corporation's future performance and development depend to a significant extent on the abilities, experience and efforts of its management team. The Corporation's ability to retain its management team or attract suitable replacements should key members of the management team leave is dependent on the competitive nature of the employment market.

The loss of services from key members of the management team or a limitation in their availability could adversely impact the Corporation's prospects, financial condition and cash flow.

Further, such a loss could be negatively perceived in the capital markets. The Corporation's success also depends largely upon its continuing ability to attract, develop and retain skilled employees to meet its needs from time to time.

Litigation

In the normal course of its operations, the Corporation may become involved in various legal actions, including but not limited to those involving claims relating to contract disputes, personal injuries, property damage, property taxes and land rights. The Corporation maintains adequate provisions for its outstanding or pending claims, including those identified under section "Legal Proceedings and Regulatory Actions". The final outcome with respect to outstanding, pending or future actions cannot be predicted with certainty, and therefore there can be no assurance that their resolution will not have an adverse effect on the financial position or results of operation of the Corporation in a particular quarter or financial year.

Performance of Major Counterparties

The Corporation enters into purchase orders with third-party suppliers for generation equipment for projects under construction, generator interconnection agreements with utilities and other interconnection providers for transmission infrastructure and the right to interconnect such projects, each of which involves deposits prior to equipment being delivered and it also enters into construction agreements with contractors and other third parties. Should one or more of these suppliers or contractors be unable to meet their obligations under the contracts, this would result in possible loss of revenue, delay in construction and increase in construction costs for the Corporation. Failure of any equipment supplier, contractor or transmission provider to meet its obligations to the Corporation may result in the Corporation not being able to meet its commitments and thus lead to potential defaults under PPAs or power hedges.

Social Acceptance of Renewable Energy Projects

The social acceptance by local stakeholders, including, in some cases, First Nations and other Indigenous peoples, and local communities is critical to our ability to find and develop new sites suitable for viable renewable energy projects. Failure to obtain proper social acceptance for a project may prevent the development and construction of a project and lead to the loss of all investments made in the development and the write-off of such prospective project.

Relationships with Stakeholders

The Corporation enters into various types of arrangements with communities or joint venture partners for the development of its projects. Certain of these partners may have or develop interests or objectives which are different from or even in conflict with the objectives of the Corporation. Any such differences could have a negative impact on the success of the Corporation's projects. The Corporation is sometimes required through the permitting and approval process to notify and consult with various stakeholder groups, including landowners, indigenous communities and municipalities. Any unforeseen delays in this process may negatively impact the ability of the Corporation to complete any given project on time or at all.

Equipment Supply

The Corporation's development and operation of power facilities is dependent on the supply of equipment from third parties. Equipment pricing may rapidly increase depending, among others, on the equipment availability, the raw material prices and on the market for such product. Any significant increase in the price of supply of equipment could negatively affect the future profitability of the Corporation's facilities and the Corporation's ability to develop other projects. There is no guarantee that manufacturers will meet all their contractual obligations. Failure of any supplier of the Corporation to meet its commitments would adversely affect the Corporation's ability to complete projects on schedule and to honour its obligations under PPAs.

Exposure to Many Different Forms of Taxation in Various Jurisdictions

The Corporation is subject to many different forms of taxation in various jurisdictions throughout the world, including but not limited to, income tax, withholding tax, tax on capital, property tax, sales tax, transfer tax, social security and other payroll related taxes, which may be amended or may lead to disagreements with tax authorities regarding the application of tax law. Tax law and administration is extremely complex and often requires the Corporation to make subjective determinations. The computation of taxes involves many factors, including the interpretation of tax legislation in various jurisdictions in which the Corporation is or may become subject to tax assessments. The Corporation's estimate of tax related assets, liabilities, recoveries and expenses incorporates significant assumptions. These assumptions include, but are not limited to, the tax rates in various jurisdictions, the effect of tax treaties between jurisdictions and taxable income projections. To the extent that such assumptions differ from actual results, the Corporation may have to record additional tax expenses and liabilities, including interest and penalties.

Changes in General Economic Conditions
Changes in general economic conditions could have an effect on the assessment of the value of the Corporation's assets, affecting its ability to raise capital, through financing, re-financing, divestiture of certain assets or generally its ability to execute its strategy. Furthermore, most of the PPAs of the Corporation have fixed price adjusted annually for inflation on a CPI formula basis. If the inflation is lower than expected or if it decreases, the Corporation's projected revenues and Projected Adjusted EDITDA and free cash flow may be lower than expected or reduced which would respectively impact the payout ratio.

Regulatory and Political Risks
The development and operation of power generating facilities are subject to changes in governmental regulatory requirements and the applicable governing statutes, including regulations related to the environment, unforeseen environmental effects, general economic conditions and other matters beyond the control of the Corporation.

Moreover, the operation of power generating facilities is subject to extensive regulation by various government agencies at the municipal, provincial, state and federal levels. There is always the risk of changes being made in government policies and laws which may result in increased rates, such as for water rentals, and for income, capital and municipal taxes.

The Corporation holds permits and licences from various regulatory authorities for the construction and operation of its facilities. These licences and permits are critical to the operation of the Corporation's business. Most of these permits and licences are long-term in nature, reflecting the anticipated useful life of the facilities. In some cases, these permits may need to be renewed prior to the end of the anticipated useful life of such facilities and there is no guarantee that such renewals will be granted or on which conditions they will be renewed. These permits and licences require the Corporation's compliance with the terms thereof.

Ability to Secure Appropriate Land
There is significant competition for appropriate sites for new power generating facilities. Optimal sites are difficult to identify and obtain given that geographic features, legal restrictions and ownership rights naturally limit the areas available for site development. There can be no assurance that the Corporation will be successful in obtaining any particular site in the future.

Reliance on Various Forms of PPAs
The power generated by the Corporation is mostly sold under long-term power purchase agreements and in some cases under power hedges and commercial or industrial retail contracts. If, for any reason, any of the purchasers of power under such PPAs were unable or unwilling to fulfill their contractual obligations under the relevant PPA or if they refuse to accept delivery of power pursuant to the relevant PPA, the Corporation's business, operating results, financial condition or prospects could be adversely affected. If the Development Projects are not brought into commercial operation within the delay stipulated in their respective PPA or power hedges, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related PPA or power hedges.

Availability and Reliability of Transmission Systems
The Corporation's ability to sell electricity is impacted by the availability of the various transmission systems in each jurisdiction. The failure of existing transmission facilities, the lack of adequate transmission capacity or delays in construction would have a material adverse effect on the Corporation's ability to deliver electricity to its various counterparties or to the point of interconnection, thereby affecting the Corporation's business, operating results, financial condition or prospects.

Foreign Market Growth and Development risks
The Corporation may, regarding any international expansion of its activities, face risks related to (i) its ability to effectively consummate future acquisitions, create new partnerships and develop, construct and operate projects in an unfamiliar regulatory and procurement market (ii) competing with more established competitors, (iii) foreign exchange fluctuations, (iv) lack of knowledge of foreign market and (v) changes in international and local taxation.

Foreign Exchange Fluctuations
The Corporation occasionally purchases equipment from foreign suppliers. As such, the Corporation may be exposed to changes in the Canadian dollar in relation to the foreign currency denominated equipment purchases. Our development work and operations in Canada, France, the U.S. and Latin America make us subject to foreign currency fluctuations.

Some of our revenue and costs are denominated in currencies other than the Canadian dollar. Foreign exchange fluctuations may impact our results as they are reported in Canadian dollars.

Our functional and reporting currency is the Canadian dollar. As such, our foreign investments, operations costs and assets will be exposed to net changes in currency exchange rates. Volatility in exchange rates could have an adverse effect on our business, financial condition and operating results.

Increase in Water Rental Cost or Changes to Regulations Applicable to Water Use
The Corporation is required to make rental payments for water rights once its projects are in commercial operation. Significant increases in water rental costs in the future or changes in the way that governments who regulate water supply or apply such regulations (including those of Québec, BC, Ontario, Idaho, U.S. and Chile) where the Corporation has hydroelectric Operating Facilities, could have a material adverse effect on the Corporation's business, operating results, financial condition or prospects.

Assessment of Water, Wind and Solar and Associated Electricity Production
The strength and consistency of the water, wind and solar resources at power facilities of the Corporation may vary from what the Corporation anticipates. Electricity production estimates of the Corporation are based on assumptions and factors that are inherently uncertain, which may result in actual electricity production being different from the estimates of the Corporation, including (i) the extent to which the limited time period of the site-specific hydrological, wind or solar data accurately reflects long-term water flows, wind speeds and solar radiation; (ii) the extent to which historical data accurately reflects the strength and consistency of the water, wind and solar resources in the future; (iii) the strength of the correlation between the site-specific water, wind and solar data and the longer-term regional data; (iv) the potential impact of climatic factors and climatic change; (v) the accuracy of assumptions on a variety of factors, including but not limited to weather, icing and soiling of water and wind turbines and snow on solar panels, site access, wake and line losses and wind shear; (vi) the accuracy with which anemometers measure wind speed, and the difference between the hub height of the wind turbines and the height of the meteorological towers used for data collection; (vii) the potential impact of topographical variations, turbine placement and local conditions, including vegetation; (viii) the inherent uncertainty associated with the specific methodologies and related models, in particular future-orientated models, used to project the water, wind and solar resource; and (ix) the potential for electricity losses to occur before delivery.

Global Climate Change
Global climate change, including the impacts of global warming, represents a physical and a financial risk which could adversely affect the Corporation's business, results of operations and cash flows. Variability in hydrology, wind regimes and solar irradiation and their predictability may be affected by unforeseen climate changes such as hurricanes, wind storms, hailstorms, rainstorms, ice storms, floods, severe winter weather and forest fires. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

The Corporation carefully manages physical risks, including preparing for, and responding to, extreme weather events through activities such as proactive route selection, asset hardening, regular maintenance, and insurance. The Corporation follows regulated engineering codes, evaluates ways to create greater system reliability and resiliency and, where appropriate, submits regulatory applications for capital expenditures aimed at creating greater system reliability and resiliency within the code. When planning for capital investment or acquiring assets, site specific climate and weather factors, such as flood plain mapping and extreme weather history, are considered. Prevention activities include wildfire management plans and vegetation management at electricity transmission and distribution sites. The Corporation maintains in-depth emergency response measures for extreme weather events.

Natural Disasters and Force Majeure
The Corporation's facilities, operations and project under development are exposed to potential damage, partial or full loss, resulting from environmental disasters (e.g. floods, high winds, fires, and earthquakes), equipment failures or other unforeseen event. The occurrence of a significant event which disrupts or delay the ability of the Corporation's power generation assets to produce or sell power for an extended period, including events which preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on the business of the Corporation. The Corporation's generation assets could be exposed to effects of severe weather conditions, natural disasters and potentially catastrophic events such as a major accident or incident. The occurrence of such an event may not release the Corporation from performing its obligations pursuant to PPAs or other agreements with third parties. Furthermore, force majeure events affecting our assets could result in damages to the environment or harm third parties. In addition, many of the Corporation's projects are in remote areas which make access for repair of damage difficult.

Cybersecurity
The Corporation is dependent on various information technologies to carry out multiple business activities. A successful cyber intrusion, such as, and not limited to, unauthorized access, malicious software or other violations on the system that control generation and transmission at any of our offices or facilities could severely disrupt or otherwise affect business operations or diminish competitive advantages. These attacks on our information base systems through theft, alteration or destruction could

generate unexpected expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. A breach of our cyber/data security measures could have a material adverse effect on the Corporation's business, operations, financial condition and operating results.

Sufficiency of Insurance Coverage
While the Corporation maintains insurance coverage, there is no certainty that such insurance will continue to be offered on an economically feasible basis, nor that all events that could give rise to a loss or liability are insurable, nor that the amounts of insurance will at all times be sufficient to cover each and every loss or claim that may occur involving our activities or assets.

Credit Rating May Not Reflect Actual Performance of the Corporation or a Lowering (Downgrade) of the Credit Rating
The credit ratings applied to the Corporation, the Series A and Series C Shares (the "Credit Ratings") are an assessment, by the rating agencies, of the Corporation's ability to pay its obligations. The Credit Ratings are based on certain assumptions about the future performance and capital structure of the Corporation that may or may not reflect the actual performance or capital structure of the Corporation. Changes in the Credit Ratings in the future may affect the market price or value and the liquidity of the securities of the Corporation. There is no assurance that any Credit Ratings will remain in effect for any given period or that any rating will not be lowered or withdrawn entirely by the rating agencies.

Revenues from Certain Facilities Will Vary Based on the Market (or Spot) Price of Electricity
Because the prices for electricity purchased from certain Operating Facilities vary based on the market price for electricity (including the Miller Creek Facility is based on a formula using the Platts mid-C spot price for electricity), revenues from such facilities on the electricity market or under the applicable power purchase agreement will vary. Without limiting the generality of the above, for the Miller Creek Facility, if the Platts mid-C index declines from its current levels, the Miller Creek Facility's revenues and adjusted EBITDA will be negatively impacted. An increase in the volatility of the Platts mid-C spot price would add uncertainty to the determination of potential revenues and adjusted EBITDA of the Miller Creek Facility and could have an adverse impact on the Corporation's results.

Risks related to U.S. Production and Investment Tax Credits, Changes in U.S. Corporate Tax Rates and Availability of Tax Equity Financing
The Corporation owns interest in projects for which on and off-site project activities are or were performed to qualify for U.S. renewable tax incentives (PTCs or ITCs). There can be no assurance that the projects will qualify for PTCs or ITCs or, if they do, that they will qualify for full PTCs or ITCs. There also can be no assurance that the PTCs or ITCs will continue to be available. Any new tax rule, regulation or other guidance promulgated (as the same may be amended, updated or otherwise modified from time to time, including those amendments passed in late 2017) in the U.S. may jeopardize or otherwise impede the effectiveness of such on and off-site project activities qualifying such projects for the full value of PTCs.

Qualification of the projects for PTCs or ITCs is critical to obtaining tax equity financing for wind projects. The inability to qualify the projects for PTCs or ITCs, in whole or in part, would adversely affect the financing options for those projects. If the qualification of a project for PTCs or ITCs is not successful, there may be a material impairment of the Corporation's investment in that project.

Other government actions could be taken that could, directly or indirectly, inhibit the Corporation's ability to raise tax equity financing. For example, following the tax reform enacted in late-2017, lower corporate tax rates in the U.S. may impact the amount of available tax equity investment for specific projects or generally in the market, impeding our ability to obtain enough amounts of tax equity investment on terms and at rates beneficial to the Corporation and its projects.

Host Country Economic, Social and Political Conditions
Several the Corporation's principal assets are located in foreign domiciles. Although the operating environments in these jurisdictions are considered favourable compared to that in other countries, there are still economic, social and political risks associated with operating in foreign jurisdictions. These risks include, but are not limited to, terrorism, hostage taking, war, civil unrest or military repression, expropriation, repatriation or nationalization without adequate compensation, extreme fluctuations in currency exchange rates, high rates of inflation and labour unrest, renegotiation or nullification of existing concessions, licenses, permits and contracts, difficulties enforcing judgments in such jurisdictions, changes to tax and royalty regimes, changes to environmental regulatory regimes, volatile local political, legal and economic climates, nepotism, subsidies directed at industries competing with ours, difficulties obtaining key equipment and components for equipment, currency control and host-country favourable legislation.

Host country economic, social and political uncertainty can arise as a result of lack of support for our activities in local communities in the vicinity of our properties. Changes in renewable resource, energy or investment policies or shifts in political attitudes may also adversely affect the Corporation's business. The effect of these factors cannot be accurately predicted. Though the effects of competition will increase the likelihood of market efficiencies and benefit our properties, elimination of power cost subsidies may increase the inability of end-use consumers to pay for power and lead to political opposition to privatization initiatives and have an adverse impact on our properties and operations.

Risks Inherent to Rockslides, Avalanches, Tornados, Hurricanes or Other Occurences Outside Corporation's Control
Hazards such as unusual or unexpected geologic formations, pressures, downhole conditions, rockslides, other events associated with steep terrain, mechanical failures, blowouts, cratering, localized ground subsidence, localized ground inflation, pollution and other physical and environmental risks can affect our development and production activities. These hazards could result in substantial losses including injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations.

Adverse Claims to Property Title
Although the Corporation has taken reasonable precautions to ensure that legal title to its properties is properly documented, there can be no assurance of title to any of its property interests, or that such title will ultimately be secured. However, the results of the Corporation’s investigations should not be construed as a guarantee of title. No assurance can be given that applicable governments will not revoke or significantly alter the conditions of the applicable exploration and mining authorizations nor that such exploration and mining authorizations will not be challenged or impugned by third parties. The Corporation’s property interests may also be subject to prior unregistered agreements or transfers or other land claims, and title may be affected by undetected defects and adverse laws and regulations.?

The Corporation cannot guarantee that title to its properties will not be challenged. Title insurance is not always available, or available on acceptable terms, and the Corporation’s ability to ensure that it has obtained secure claim to individual properties may be severely constrained. A successful challenge to the precise area and location of these claims could result in the Corporation being unable to operate on its properties as permitted or being unable to enforce its rights with respect to its properties.

Unknown Liabilities
As part of the Corporation’s completed and future acquisitions, it has assumed liabilities and risks. While the Corporation conducted due diligence, there may be liabilities or risks that the Corporation failed, or was unable, to discover in the course of performing the due diligence investigations or for which the Corporation was not indemnified. Any such liabilities, individually or in the aggregate, could have a material adverse effect on the Corporation’s financial position and results of operations.

Reliance on Intellectual Property and Confidential Agreements to Protect our Rights and Confidential Information
The Corporation’s success and competitive position are dependent in part upon our proprietary methods and intellectual property. Although the Corporation seeks to protect its proprietary rights through a variety of means, it cannot guarantee that the protective steps it has taken are adequate to protect these rights.

The Corporation also relies on confidentiality agreements with certain employees, consultants and other third parties to protect, in part, trade secrets and other proprietary information. These agreements could be breached, and the Corporation may not have adequate remedies for such a breach. In addition, others could independently develop substantially equivalent proprietary information or gain access to the Corporation’s trade secrets or proprietary information.

Reputational RIsks Arising from Misconduct of Representatives of the Corporation
The Corporation’s success can be impacted by events affecting its reputation. In some cases, the Corporation may be affected or be held accountable for the actions of directors, officers or employees of the Corporation and those of third parties who act for or on behalf of the Corporation. Although the Corporation seeks to protect its reputation through Corporation's internal policies, procedures and controls, there is a risk that events or actions of certain representatives of the Corporation could affect its reputation. Adverse effects on the Corporation’s reputation could affect its relationships with various stakeholders, partners, governments, employees, shareholders and the general public. This could, among other things, result in lost business opportunities, loss of revenue, litigation and reduce the Corporation’s ability to raise additional capital. Reputational harm could also reduce our ability to attract new talent or retain officers and key employees, decrease social acceptance of renewable energy projects and affect government support to increase electricity to be generated by independent power producers.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in conformity with IFRS requires management to make estimates and assumptions that 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 periods, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment, intangible assets, project development costs and goodwill, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives, effectiveness of hedging relationships and classification of structured entities. 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.

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 unless hedge accounting is used, in which case the changes are recognized in comprehensive income. Fair values of some financial instruments are estimated by using valuation techniques that require several assumptions such as interest rate, credit spread, exchange rates, forward prices and other.

Useful Lives of Property, plant and equipment and Intangible assets

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

Impairment of non-financial assets

The Corporation makes a number of estimates when calculating the recoverable amount of an asset or a cash-generating unit using value in use calculations based on discounted future cash flows. Future cash flows may be influenced by a number of estimates such as electricity production, duration of the projects, selling prices, costs to operate, capital expenditures, growth rate and the discount rate. The likelihood of being able to develop future projects is also assessed in respect of the competitive business environment and the willingness expressed by the governmental authorities to procure additional sources of energy.

Business acquisition fair value

The Corporation makes a number of estimates when determining the acquisition date fair values of consideration transferred, assets acquired and liabilities assumed in a business acquisition. Fair values are estimated using valuation techniques that require several assumptions such as future production, earnings and expenses and discount rates.

Determining control, joint control or significant influence of an investee

The determination of whether the Corporation has control, joint control or significant influence over an investee requires the Corporation to make assumptions and judgments in evaluating the classification requirements.

Based on the contractual arrangements between the Corporation and the other respective partner, and the fact that the Corporation owns more than 50% of the economic interest, the Corporation concluded that it has control over Kwoiek Creek Resources L.P., Mesgi'g Ugju's'n (MU) Wind Farm L.P., Kokomo Solar 1, LLC, Spartan PV 1, LLC, Foard City Wind, LLC and Phoebe Energy Project, LLC.

Asset retirement obligations

The Corporation makes a number of estimates when calculating fair value of the asset retirement obligations that represent the present value of future remediation costs for various projects. Estimates for these costs are dependent on labour costs, the effectiveness of remedial and restoration measures, inflation rates, discount rates that reflect a current market assessment of the time value of money and the risk specific to the obligation, and the timing of the outlays.

Hedging

The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

The Corporation may, from time to time, enter into long-term power hedge agreements that require critical judgments to determine the fair value and the designation of the long-term power hedge. As part of the designation of the power hedges as cash flow hedges, the Corporation makes certain judgments regarding the probability of future events. As part of determining fair value, the Corporation makes certain assumptions, estimates and judgments regarding future events. Unobservable forecast future power prices are inherently subjective and impact the change in fair value recognized in the consolidated statement of earnings and the consolidated statement of comprehensive loss.

CHANGE IN ACCOUNTING POLICIES

New Accounting Standards and Interpretations Adopted During the Year

IFRS 16, *Leases*

On January 13, 2016, the IASB issued IFRS 16, *Leases* ("IFRS 16") which provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. It supersedes IAS 17, *Leases* and its associated interpretive guidance. Significant changes were made to lessee accounting with the distinction between operating and finance leases removed and assets and liabilities recognized in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). In contrast, IFRS 16 does not include significant changes to the requirements for lessors. The Corporation adopted this standard retrospectively on January 1, 2019 without restating the figures for the comparative periods, as permitted under the specific transitional provisions in the standard (modified retrospective approach).

The following table shows the effects of the application of IFRS 16 on the opening balances on the consolidated statement of financial position as at January 1, 2019:

	Hydroelectric	Wind	Solar	Site development/ Corporate	Total
Current assets					
Prepaid and others	—	(1,640)	(50)	—	(1,690)
Non-current assets					
Right-of-use assets presented in Property, plant and equipment	2,775	56,652	839	63,622	123,888
Current liabilities					
Accounts payable and other payables	—	(72)	—	—	(72)
Lease liabilities presented in other liabilities	50	2,410	12	2,612	5,084
	50	2,338	12	2,612	5,012
Non-current liabilities					
Lease liabilities presented in other liabilities	2,725	52,674	777	61,010	117,186

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

Tax equity investments

During the year ended December 31, 2019, the Corporation proceeded to a change in the method of accounting for tax equity financing, as previously recorded as an element of equity, which resulted in a reclassification of the tax equity financing as financial liabilities. The change was applied during the fourth quarter of 2019. Comparative figures have been adjusted to conform to the current year's presentation. The change resulted in the following reclassifications:

Consolidated Statements of Financial Position

	As at December 31 2018
Property, plant and equipment	(12,265)
Investments in joint ventures and associates	47,139
Total assets	34,874
Current portion of long-term loans and borrowings and other liabilities	(208)
Long-term loans and borrowings	(503)
Deferred tax liabilities	53,109
Total liabilities	52,398
Deficit	(1,552)
Accumulated other comprehensive income	1,021
Non-controlling interests	(16,993)
Total shareholders' equity	(17,524)
Total liabilities and shareholders' equity	34,874

Consolidated Statements of Earnings

	Year ended December 31 2018
Depreciation	(670)
Finance costs	186
Other net revenues	(764)
Share of earnings of joint ventures and associates	(22,248)
Earnings before income taxes	(23,496)
Deferred income tax expense	23,496
Net earnings and net earnings from continuing operations	—
Attributable to:	
Owners of the parent	(1,552)
Non-controlling interests	1,552

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

Amendments to IFRS 9, *Financial Instruments (Interest rate benchmark reform)*

On September 26, 2019, the IASB issued amendments for some of its requirements for hedge accounting in IFRS 9 Financial Instruments in relation to Phase 1 of IBOR Reform and its Effects on Financial Reporting project. The amendments are effective for periods beginning on or January 1, 2020, with early adoption permitted. The Corporation has applied the interest rate benchmark reform amendments retrospectively to hedging relationships that existed at January 1, 2019 or were designated thereafter and that are directly affected by the interest rate benchmark reform. These amendments also apply to the gain or loss recognized in OCI that existed at January 1, 2019.

Non-Wholly Owned Subsidiaries

Prior to its acquisition by the Corporation on February 6, 2018, Alterra was accounting for Kokomo and Spartan as joint ventures using the equity method. On December 31, 2018, the Corporation completed its review of the various partnership agreements and concluded it has control over these entities and as such, they should be consolidated. This change has been reflected in the consolidated financial statements for the year ended December 31, 2018, but these entities were accounted for as joint ventures using the equity method in all of the 2018 condensed interim consolidated financial statements.

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

In accordance with Regulation 52-109 respecting Certification of Disclosure in Issuers' Annual and Interim Filings, the President and Chief Executive Officer and the Chief Financial Officer of the Corporation have designed, or caused to be designed under their supervision:

- Disclosure controls and procedures (“DC&P”) to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the President and Chief Executive Officer and the Chief Financial Officer by others, particularly during the period in which the 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 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.

The President and Chief Executive Officer and the Chief Financial Officer of the Corporation have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation’s DC&P and ICFR as at December 31, 2019, and have concluded that they were effective at the financial year-end. During the period beginning on October 1, 2019 and ended on December 31, 2019, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENTS

Strategic Alliance and Private Placement with Hydro-Québec

- On February 6, 2020, the Corporation announced that it formed a Strategic Alliance with Hydro-Québec to accelerate its growth with investments in larger and more diversified projects. Hydro-Québec committed an initial $500 million for future co-investments with the Corporation.
- Hydro-Québec invested $661 million through a Private Placement of Innergex common shares at a price of $19.08 per share, representing a premium of 5.0% to the 30-day volume weighted average price as at February 5, 2020 and a total of 34.6 million shares (the “Private Placement”).

Responsibility for Financial Reporting

The consolidated financial statements of Innergex Renewable Energy Inc. (the "Corporation") and the management's discussion and analysis 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 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 safeguarded.

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 auditors' report. The Audit Committee submits its findings 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 an 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, KPMG LLP, in accordance with **Canadian generally accepted auditing standards** and on the shareholders' behalf. KPMG LLP enjoys full and unrestricted access to the Audit Committee.

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

[s] Jean-François Neault
Jean-François Neault, CPA, CMA, MBA
Chief Financial Officer

Innergex Renewable Energy Inc.

Longueuil, Canada, February 27, 2020

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Innergex Renewable Energy Inc.

Opinion

We have audited the consolidated financial statements of Innergex Renewable Energy Inc. (the Entity), which comprise:

- the consolidated statement of financial position as at December 31, 2019 and December 31, 2018;
- the consolidated statement of earnings for the year then ended;
- the consolidated statement of comprehensive income (loss) for the year then ended;
- the consolidated statement of changes in shareholders' equity for the year then ended;
- the consolidated statement of cash flows for the year then ended;
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at December 31, 2019 and December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

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

Emphasis of Matter - Change in Accounting Policy

We draw attention to Note 2 to the financial statements which indicates that the Entity has changed its accounting policy for leases as of January 1, 2019, due to the adoption of IFRS 16, Leases, and has applied that change using a modified retrospective transition approach.

Our opinion is not modified in respect of this matter.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions;
- the information, other than the financial statements and the auditors' report thereon, included in the "2019 Annual Report".

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions and the information, other than the financial statements and the auditors' report thereon, included in the "2019 Annual Report" as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

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

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group Entity to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

KPMG LLP*

The engagement partner on the audit resulting in this auditors' report is Girolamo Cordi.

Montréal, Canada
February 27, 2020

CONSOLIDATED STATEMENTS OF EARNINGS

	Notes	Year ended December 31 2019	2018
Revenues		557,042	481,418
Expenses			
Operating	6	98,455	84,724
General and administrative	6	36,507	27,796
Prospective projects	6	12,905	16,719
Earnings before the following:		409,175	352,179
Depreciation	6,16	153,617	111,083
Amortization	6,17	40,962	40,173
Impairment of project development costs	18	8,184	—
Earnings before the following:		206,412	200,923
Finance costs	7	231,766	195,834
Other net (revenues) expenses	8	(104,643)	12,183
Share of earnings of joint ventures and associates	9	(36,469)	(47,596)
Unrealized net loss (gain) on financial instruments	10	49,933	(12,958)
Earnings before income taxes		65,825	53,460
Provision for income taxes			
Current	11	16,845	8,521
Deferred	11	102,006	18,724
		118,851	27,245
Net (loss) earnings from continuing operations		(53,026)	26,215
Net earnings (loss) from discontinued operations	5	21,815	(497)
Net (loss) earnings		(31,211)	25,718
Net (loss) earnings attributable to:			
Owners of the parent		(28,041)	31,140
Non-controlling interests	26	(3,170)	(5,422)
		(31,211)	25,718
(Loss) earnings per share from continuing operations attributable to owners:			
Basic net (loss) earnings per share ($)	12	(0.40)	0.20
Diluted net (loss) earnings per share ($)	12	(0.40)	0.20
(Loss) earnings per share attributable to owners:			
Basic net (loss) earnings per share ($)	12	(0.25)	0.19
Diluted net (loss) earnings per share ($)	12	(0.25)	0.19

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

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Notes	Year ended December 31 2019	2018
Net (loss) earnings		(31,211)	25,718
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:	24		
Foreign currency translation differences for foreign operations		(31,713)	22,786
Foreign exchange gain (loss) on the designated hedges on the net investments in foreign operations		4,021	(6,199)
Change in fair value of financial instruments designated as cash flow hedges		23,688	(49,404)
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges		(1,872)	(59)
Related deferred income taxes		(2,197)	11,290
Other comprehensive loss from continuing operations		(8,073)	(21,586)
Other comprehensive income (loss) from discontinued operations	5	3,928	(36,838)
Other comprehensive loss		(4,145)	(58,424)
Total comprehensive loss		(35,356)	(32,706)
Total comprehensive loss attributable to:			
Owners of the parent		(9,158)	(13,281)
Non-controlling interests		(26,198)	(19,425)
		(35,356)	(32,706)

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

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	December 31, 2019	December 31, 2018
ASSETS			
Current assets			
Cash and cash equivalents		156,224	79,586
Restricted cash	13	39,451	29,981
Accounts receivable	14	92,265	103,886
Derivative financial instruments	10	5,419	2,370
Prepaid and other		12,273	12,454
Total current assets		305,632	228,277
Non-current assets			
Property, plant and equipment	16	4,620,025	4,470,663
Intangible assets	17	682,227	925,009
Project development costs	18	11,135	30,119
Investments in joint ventures and associates	9	511,899	651,912
Derivative financial instruments	10	78,251	9,817
Deferred tax assets	11	30,264	16,465
Goodwill	19	60,666	109,995
Other long-term assets	15	72,005	73,901
Total non-current assets		6,066,472	6,287,881
Total assets		6,372,104	6,516,158
LIABILITIES			
Current liabilities			
Accounts payable and other payables	20	176,157	164,860
Derivative financial instruments	10	51,093	29,999
Current portion of long-term loans and borrowings and other liabilities	21, 22	414,103	446,433
Total current liabilities		641,353	641,292
Non-current liabilities			
Derivative financial instruments	10	112,625	118,002
Long-term loans and borrowings	21	4,281,586	4,262,469
Other liabilities	22	292,421	173,345
Deferred tax liabilities	11	428,793	379,013
Total non-current liabilities		5,115,425	4,932,829
Total liabilities		5,756,778	5,574,121
SHAREHOLDERS' EQUITY			
Equity attributable to owners	23	604,384	629,261
Non-controlling interests	26	10,942	312,776
Total shareholders' equity		615,326	942,037
Total liabilities and shareholders' equity		6,372,104	6,516,158

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

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Equity attributable to owners								
Year ended December 31, 2019	Common share capital account	Contributed surplus	Preferred shares	Convertible debentures	Deficit	Accumulated other comprehensive income (loss)	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2019	6,546	1,272,604	131,069	3,976	(750,442)	(34,492)	629,261	312,776	942,037
Net loss	—	—	—	—	(28,041)	—	(28,041)	(3,170)	(31,211)
Other comprehensive income (loss)	—	—	—	—	—	18,883	18,883	(23,028)	(4,145)
Total comprehensive (loss) income	—	—	—	—	(28,041)	18,883	(9,158)	(26,198)	(35,356)
Common shares issued through dividend reinvestment plan	2,402	—	—	—	—	—	2,402	—	2,402
Share-based payments	—	64	—	—	—	—	64	—	64
Common share options exercised	1,323	(4,357)	—	—	—	—	(3,034)	—	(3,034)
Convertible debentures converted into common shares and redemption (Note 21)	88,272	—	—	(1,877)	—	—	86,395	—	86,395
Convertible debentures issued (net of $279 of deferred income taxes) (Note 21)	—	—	—	770	—	—	770	—	770
Shares vested - Performance Share Plan	1,057	—	—	—	—	—	1,057	—	1,057
Shares purchased - Performance Share Plan	(2,385)	—	—	—	—	—	(2,385)	—	(2,385)
Buyback of non-controlling interests	—	—	—	—	—	—	—	(218)	(218)
Sale of discontinued operations (Note 5)	—	—	—	—	—	—	—	(260,846)	(260,846)
Dividends declared on common shares	—	—	—	—	(95,046)	—	(95,046)	—	(95,046)
Dividends declared on preferred shares	—	—	—	—	(5,942)	—	(5,942)	—	(5,942)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(14,572)	(14,572)
Reclassification of defined benefit plan actuarial losses	—	—	—	—	(378)	378	—	—	—
Balance December 31, 2019	97,215	1,268,311	131,069	2,869	(879,849)	(15,231)	604,384	10,942	615,326

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

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Equity attributable to owners								
Year ended December 31, 2018	Common shares capital account	Contributed surplus	Preferred shares	Convertible debentures	Deficit	Accumulated other comprehensive (loss) income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2018	2,867	940,760	131,069	1,877	(648,160)	9,929	438,342	14,920	453,262
Net earnings (loss)	—	—	—	—	31,140	—	31,140	(5,422)	25,718
Other comprehensive income	—	—	—	—	—	(44,421)	(44,421)	(14,003)	(58,424)
Total comprehensive income (loss)	—	—	—	—	31,140	(44,421)	(13,281)	(19,425)	(32,706)
Common shares issued on February 6, 2018	330,607	—	—	—	—	—	330,607	—	330,607
Business acquisitions (Note 4)	—	—	—	—	—	—	—	296,536	296,536
Common shares issued through dividend reinvestment plan	9,929	—	—	—	—	—	9,929	—	9,929
Reduction of capital on common shares	(337,785)	337,785	—	—	—	—	—	—	—
Buyback of common shares	(20)	(6,010)	—	—	(3,457)	—	(9,487)	—	(9,487)
Share-based payments	—	69	—	—	—	—	69	—	69
Equity portion of convertible debentures issued (net of $766 of deferred income taxes)	—	—	—	2,099	—	—	2,099	—	2,099
Shares vested - Performance Share Plan	948	—	—	—	—	—	948	—	948
Buyback of non-controlling interests	—	—	—	—	(33,808)	—	(33,808)	32,108	(1,700)
Investments from non-controlling interests	—	—	—	—	—	—	—	507	507
Dividends declared on common shares	—	—	—	—	(90,215)	—	(90,215)	—	(90,215)
Dividends declared on preferred shares	—	—	—	—	(5,942)	—	(5,942)	—	(5,942)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(11,870)	(11,870)
Balance December 31, 2018	6,546	1,272,604	131,069	3,976	(750,442)	(34,492)	629,261	312,776	942,037

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

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Notes	Year ended December 31 2019	2018
OPERATING ACTIVITIES			
Net (loss) earnings		(31,211)	25,718
Net (loss) earnings from discontinued operations		(21,815)	497
Net (loss) earnings from continuing operations		(53,026)	26,215
Items not affecting cash:			
Depreciation and amortization	16,17	194,579	151,256
Impairment of project development costs	18	8,184	—
Share of earnings of joint ventures and associates	9	(36,469)	(47,596)
Unrealized net loss (gain) on financial instruments	10	49,933	(12,958)
Production tax credits and tax attributes allocated to tax equity investors	8	(99,640)	(764)
Other		(4,153)	2,533
Finance costs expense	7	231,766	195,834
Finance costs paid	25	(195,915)	(170,960)
Realized loss on financial instruments	10	(16,050)	—
Distributions received from joint ventures and associates	9	19,498	19,042
Provision for income taxes	11	118,851	27,245
Income taxes paid		(17,007)	(4,373)
Effect of exchange rate fluctuations		3,990	(879)
		204,541	184,595
Changes in non-cash operating working capital items	25	22,402	(8,648)
Cash flows from operating activities from continuing operations		226,943	175,947
Cash flows from operating activities from discontinued operations		13,122	33,443
		240,065	209,390
FINANCING ACTIVITIES			
Dividends paid on common shares		(90,856)	(75,599)
Dividends paid on preferred shares		(5,942)	(5,942)
Distributions to non-controlling interests		(11,490)	(6,843)
Increase of long-term debt, net of deferred financing costs	25	1,686,972	2,026,449
Repayment of long-term debt	25	(1,323,827)	(1,111,079)
Payment of lease liabilities	22	(4,756)	—
Payment for redemption of convertible debentures	21	(13,348)	—
Net proceeds from issuance of convertible debentures	21	137,214	143,090
Repurchase of common shares		(2,385)	(9,487)
Payment of payroll deductions on exercise of share options		(3,034)	—
Cash flows from financing activities from continuing operations		368,548	960,589
Cash flows from financing activities from discontinued operations		20,059	8,382
		388,607	968,971
INVESTING ACTIVITIES			
Business acquisitions, net of cash acquired	4	—	(864,345)
Proceeds from sale of business, net of transaction costs ($6,634) and cash disposed ($13,877)	5	381,013	—
Variation in restricted cash		(14,908)	34,440
Net funds invested in the reserve accounts		(6,214)	(731)
Additions to property, plant and equipment		(847,730)	(153,381)
Additions to intangible assets		—	(2,495)
Additions to project development costs		(8,712)	(8,327)
Investments in joint ventures and associates	9	(13,756)	(134,065)
Buyback of non-controlling interests		—	(1,700)
Additions to of other long-term assets		(6,706)	(190)
Proceeds from disposal of property, plant and equipment		16	508
Cash flows used in investing activities from continuing operations		(516,997)	(1,130,286)
Cash flows used in investing activities from discontinued operations		(31,957)	(30,577)
		(548,954)	(1,160,863)
Effects of exchange rate changes on cash and cash equivalents		(3,080)	174
Net change in cash and cash equivalents		76,638	17,672
Cash and cash equivalents, beginning of year		79,586	61,914
Cash and cash equivalents, end of year		156,224	79,586

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

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

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") was incorporated under the *Canada Business Corporation Act* on October 25, 2002, and its shares and convertible debentures are listed on the Toronto Stock Exchange. The Corporation is a developer, acquirer, owner and operator of renewable power-generating facilities, essentially focused on the hydroelectric, wind and solar power sectors. The Corporation's head office is located at 1225 St-Charles Street West, 10th floor, Longueuil, QC, J4K 0B9, Canada.

These consolidated financial statements were approved by the Board of Directors on February 27, 2020.

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

Statement of Compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). The Corporation's significant accounting policies are described in Note 2. These policies have been consistently applied to all years presented, unless otherwise stated.

Basis of Measurement

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

Functional Currency and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

2. SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

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

Details of the Corporation's significant subsidiaries at the end of the reporting period are set out below.

Name of subsidiaries	Principal activity	Place of creation and operation	Proportion of ownership interest and voting rights held by the Corporation
Harrison Hydro L.P. and its subsidiaries	Own and operate hydroelectric facilities	Canada	50.01%
Kwoiek Creek Resources L.P. [1]	Own and operate a hydroelectric facility	Canada	50.00%
Ashlu Creek Investments Limited Partnership	Own and operate a hydroelectric facility	Canada	100.00%
Innergex Inc.	Own and operate hydroelectric and wind facilities	Canada	100.00%
Big Silver Creek Power Limited Partnership	Own and operate a hydroelectric facility	Canada	100.00%
Innergex Sainte-Marguerite S.E.C.	Own and operate a hydroelectric facility	Canada	50.01%
Mesgi'g Ugju's'n (MU) Wind Farm L.P. [2]	Own and operate a wind facility	Canada	50.00%
Innergex Cartier Energy LP	Own and operate wind facilities	Canada	100.00%
Innergex Europe (2015) Limited Partnership and its subsidiaries	Own and operate wind facilities	Canada/Europe	69.55%
Phoebe Energy Project LLC	Own and operate a solar facility	United States	100.00%
Foard City Holdings LLC	Own and operate a wind farm	United States	100.00%

1. The Corporation owns more than 50% of the economic interest in Kwoiek Creek Resources L.P.
2. The Corporation owns more than 50% of the economic interest in Mesgi'g Ugju's'n (MU) Wind Farm L.P.

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

Investments in joint ventures and associates

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

An associate is an entity in which the Corporation has significant influence, but not control, over the financial and operating policies. Significant influence is presumed to exist when the Corporation holds between 20% and 50% of the voting power of another entity.

The determination of whether the Corporation has control, joint control or significant influence over an investee requires the Corporation to make assumptions and critical judgments in evaluating the classification requirements.

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

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

At the end of each reporting period, the Corporation reviews the carrying amounts of its investments in joint ventures and associates to determine whether there is any indication of impairment. If any such indication exists, the recoverable amount of the net investment is estimated. Because goodwill that forms part of the carrying amount of a net investment in an associate or a joint venture is not separately recognized, it is not tested for impairment separately by applying the requirements for impairment testing of goodwill. Instead, the entire carrying amount of the investment is tested for impairment as a single asset, by comparing its recoverable amount (higher of value in use and fair value less costs to sell) with its carrying amount. Any impairment loss recognised in those circumstances forms part of the carrying amount of the net investment in the associate or joint venture and is not allocated to any asset, including goodwill. Accordingly, any reversal of that impairment loss is recognised to the extent that the recoverable amount of the net investment subsequently increases.

The Corporation discontinues the use of the equity method from the date when the investment ceases to be a joint venture or an associate. When the Corporation retains an interest in the former joint venture or associate and the retained interest is a financial asset, the Corporation measures the retained interest at fair value at that date and the fair value is regarded as its fair value on initial recognition in accordance with IFRS 9. The difference between the carrying amount of the joint venture or associate at the date the equity method was discontinued, and the fair value of any retained interest and any proceeds from disposing of a part interest in the joint venture or associate is included in the determination of the gain or loss on disposal of the joint venture or associate. In addition, the Corporation accounts for all amounts previously recognized in other comprehensive income in relation to that joint venture or associate on the same basis as would be required if that joint venture or associate had directly disposed of the related assets or liabilities. Therefore, if a gain or loss previously recognized in other comprehensive income by that joint venture would be reclassified to earnings (loss) on the disposal of the related assets or liabilities, the Corporation reclassifies the gain or loss from equity to earnings (loss) (as a reclassification adjustment) when the equity method is discontinued.

Business combinations

Business combinations are accounted for using the acquisition method. The consideration transferred is measured at the aggregate of the fair values, at the acquisition date, of assets transferred, liabilities incurred or assumed, and equity instruments issued by the Corporation in exchange for control of the acquiree. Where appropriate, the consideration transferred 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 consideration transferred 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.

Identifiable assets acquired, as well as liabilities and contingent liabilities assumed in a business combination, are measured initially at their fair values at the acquisition date, irrespective of the extent of any non-controlling interests ("NCI"). The excess of the aggregate of consideration transferred, the amount of any NCI, and in a business combination achieved in stages, the acquisition date fair value of the acquirer’s previously held equity interest in the acquiree over the fair value of the identifiable net assets acquired is recorded as goodwill. Any negative goodwill is recognized directly in the consolidated statement of earnings.

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 as required under some of its project financings.

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 various agreements.

Property, plant and equipment

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

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

The estimated useful lives, residual values and depreciation methods 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 (loss).

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.

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 (loss) in the period in which they are incurred.

The useful lives used to calculate depreciation are summarized as follows:

Type of property, plant and equipment	Useful life for the depreciation period
Hydroelectric facilities	8 to 75 years
Wind farm facilities	14 to 25 years
Solar facilities	15 to 35 years
Other equipments	3 to 10 years

Leases (policy applicable from January 1, 2019)

Nature of leasing activities

The Corporation typically leases land and offices. Lease agreements are generally made for fixed long-term periods based on each project's estimated length at inception. Land leases for a given project are usually negotiated jointly, with governments, for government-owned land, or directly with groups of private landowners for privately-owned land. Office and other leases are negotiated on an individual basis and contain a wide range of different terms and conditions. Being negotiated for long-term periods, most land leases provide for additional payments based on changes in inflation. In addition, leases generally include an option to renew the lease for an additional period after the non-cancellable contract period. The Corporation assesses at lease commencement whether it is reasonably certain to exercise the extension options. Generally the corporation aligns lease extension option renewals with estimated life of projects.

Leases are recognized as a right-of-use asset and a corresponding lease liability at the date at which the leased asset is available for use by the Corporation. Each lease payment is allocated between the lease liability and finance costs. The finance costs are charged to earnings or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

(i) Lease liabilities

Lease liabilities are recognized in other liabilities in the consolidated statement of financial position at the present value of the future lease payments, discounted using the interest rate implicit in the lease. If that rate cannot be determined, the lessee's incremental borrowing rate is used, being the rate that the lessee would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms and conditions. When determining the amount of the future lease payments, the Corporation takes the following information into account:
- fixed payments, including in-substance fixed payments, less any lease incentives receivable; and
- variable lease payment that are based on an index or a rate;

Payments associated with short-term leases and leases of low-value assets are recognized on a straight-line basis as an expense in earnings or loss. Short-term leases correspond to lease agreement with a term of 12 months or less.

Lease liabilities are subsequently measured at amortized cost using the effective interest method. A remeasurement of the lease liabilities occur when there is a change in future lease payments arising from a variation in the relevant index or rate.

(ii) Right-of-use assets

Right-of-use assets are recognized in property, plant and equipment in the consolidated statement of financial position at cost, comprising the amount of the initial measurement of the lease liability, any lease payments made at or before the commencement date and any initial direct costs.

Right-of-use asset are subsequently depreciated on a straight-line basis over the lesser of (i) the estimated useful lives of the assets or (ii) the lease term, including, when it is reasonably certain that they will be exercised, options to extend the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment.

Intangible assets

Intangible assets consist of various permits, licenses and agreements. Intangibles assets are amortized using the straight-line method over a period ending on the maturity date of the permits, licenses or agreements of each facility. The estimated useful lives reflect the respective Power Purchase Agreements' ("PPA") renewable rights periods, since it is the

Corporation's intention to exercise its option to renew its PPAs where allowable. They are recorded at cost less accumulated amortization and accumulated impairment losses. Amortization starts when the related facility becomes ready for its intended use.

The Corporation recognizes an intangible asset arising from a service concession arrangement when it has the right to charge for usage of the concession infrastructure. An intangible asset received as consideration for providing construction or upgrade services in a service concession arrangement is measured at fair value upon initial recognition. Subsequent to initial recognition, the intangible asset is measured at cost, which includes capitalized borrowing costs, less accumulated amortization and accumulated impairment losses.

Intangible assets related to facilities under construction are not amortized until the related facilities are ready for their intended use.

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

The useful lives used to calculate amortization is as follows:

Intangible assets related to:	Useful life for the amortization period
Hydroelectric facilities	4 to 75 years
Wind farm facilities	8 to 20 years
Solar facilities	20 years

Project development costs

Project development costs are recorded at cost less any impairment losses, as applicable, and represent costs incurred for the acquisition of prospective projects and for the design and development of hydroelectric, wind farm and solar sites. Borrowing costs directly attributable to the acquisition or development are capitalized as project development costs.

The Corporation defers project development costs when it becomes probable that the project will be completed and that it will generate future economic benefits that will flow to the Corporation. The Corporation makes this determination by taking into consideration various factors, either individually or combined, such as (amongst others):
◦ whether a prospective project has been granted, or whether it is probable that it will be granted, the required permits;
◦ rights of access to the required land have been secured or it is probable that they will be secured;
◦ the announcement, or the probability thereto, that a prospective project is awarded a power-purchase agreement; and
◦ access to an open market if the project is not in a market where it is expected to be awarded a power-purchase agreement.

These costs are transferred to property, plant and equipment or intangible assets at the commencement of construction. When it is no longer probable that a project will be carried out, the project's development costs deferred to that date are expensed. Current costs for prospective projects are expensed as incurred.

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

At the end of each reporting period, the Corporation reviews the carrying amounts of its non-financial assets, other than goodwill, to determine whether there is any indication of impairment. If any such indication exists, the recoverable amount of the asset is estimated. Where it is not possible to estimate the recoverable amount of an individual asset, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the “cash-generating unit”, or “CGU”). 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 discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU.

If the recoverable amount of an asset or CGU is lower than its carrying amount, the carrying amount is reduced to its recoverable amount. An impairment loss is recognized immediately in earnings (loss).

Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised recoverable amount, to the extent that the carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized. A reversal of an impairment loss is recognized immediately in earnings (loss).

Goodwill

Goodwill arises during business combinations and is measured at the acquisition date. It is subsequently measured at cost, less accumulated impairment losses (if any).

For purposes of impairment testing, goodwill is allocated to each of the Corporation's CGU (or groups of CGUs) that is expected to benefit from the synergies of the combination.

A CGU to which goodwill has been allocated is tested for impairment annually, or more frequently when there is indication that the CGU may be impaired. If the recoverable amount of the CGU is less than its carrying amount, the impairment loss is allocated first to reduce the goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU on a pro rata basis. Any impairment loss is recognized in earnings (loss). An impairment loss recognized for goodwill is not reversed in subsequent periods.

Other long-term assets

Other long-term assets include security deposits under various agreements, prepaid leases and royalty fees, reserves and long-term receivables.

The Corporation holds three types of reserve accounts designed to help ensure its financial 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, wind or solar conditions or other unpredictable events. 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. A third reserve is the dismantlement reserve aiming to have sufficient funding available for decommissioning of wind farms at the end of the projects.

The reserve accounts are currently invested in cash or in short-term investments having maturities of a year or less as well as in government-backed securities. The availability of funds in the reserve accounts may be restricted by credit agreements.

Non-current assets held for sale and discontinued operations

Non-current assets are classified as held for sale if their carrying amount will be recovered principally through a sale transaction rather than through continuing use and a sale is considered highly probable. They are measured at the lower of their carrying amount and fair value less costs to sell, except for assets such as deferred tax assets and assets arising from employee benefits, which are specifically exempt from this requirement.

Non-current assets are not depreciated or amortized while they are classified as held for sale. Interest and other expenses attributable to the liabilities directly associated with the assets classified as held for sale continue to be recognized.

Assets classified as held for sale are presented separately from the other assets in the consolidated statement of financial position. The liabilities directly associated with the assets classified as held for sale are presented separately from other liabilities in the consolidated statement of financial position.

A discontinued operation is a component of the Corporation's business that has been disposed of or is classified as held for sale and that represents a separate major line of business or geographical area of operations and is part of a single co-ordinated plan to dispose of such a line of business or area of operations. The results of discontinued operations are presented separately in the consolidated statement of earnings. Comparative figures are adjusted on the consolidated statement of earnings and on the consolidated statement of comprehensive loss as if the operations had been discontinued from the beginning of the comparative period.

Provisions and asset retirement obligations

A provision is a liability of uncertain timing or amount. Provisions are recognized into other liabilities 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 that 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 in other liabilities when those obligations are incurred and are measured at 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 periods, 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 or changes in the discounted rate. The accretion of the liability as a result of the passage of time is charged to earnings while changes resulting from the revisions to either the timing, the amount of the original estimate of the undiscounted cash flows or a change of the discount rate are accounted for as part of the carrying amount of the related property, plant and equipment. The carrying amount of the asset retirement obligations is reviewed at each quarter end to reflect current estimates and changes in the discount rate.

Provision for restructuring

A provision for restructuring is recognized when the Corporation has approved a detailed and formal restructuring plan, and the restructuring either has commenced or has been announced publicly. Restructuring provisions include only incremental costs associated directly with the restructuring. Future operating losses and other costs associated with ongoing activities are not provided for.

Financial instruments

The Corporation initially recognizes financial assets on the trade date at which the Corporation becomes a party to the contractual provisions of the instrument.

Financial assets are initially measured at fair value. If the financial asset is not subsequently accounted for at fair value through earnings (loss), then the initial measurement includes transaction costs that are directly attributable to the asset’s acquisition or origination. On initial recognition, the Corporation classifies its financial assets as subsequently measured at either amortized cost or fair value, depending on its business model for managing the financial assets and the contractual cash flow characteristics of the financial assets.

(i) Financial assets measured at amortized cost

A financial asset is subsequently measured at amortized cost, using the effective interest method and net of any impairment loss, if:

- The asset is held within a business model whose objective is to hold assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise, on specified dates, to cash flows that are solely payments of principal and/or interest.

The Corporation currently classifies its cash and cash equivalents, restricted cash, accounts receivable, and reserve accounts recognized in other long-term assets as financial assets measured at amortized cost.

(ii) Financial assets measured at fair value

These assets are measured at fair value and changes therein, including any interest or dividend income, are recognized in net earnings unless hedge accounting is used in which case the changes are recognized in other comprehensive income. Also, for investments in equity instruments that are not held for trading, the Corporation may irrevocably elect, at initial recognition, to present subsequent changes in the investment’s fair value in other comprehensive income. For such investments measured at fair value through other comprehensive income, gains and losses are never reclassified to profit or loss, and no impairment is recognized in profit or loss. Dividends earned from such investments are recognized in profit or loss, unless the dividend clearly represents a repayment of part of the cost of the investment. This election is made on an investment-by-investment basis.

The Corporation currently classifies its derivative financial instruments as financial assets measured at fair value.

The Corporation derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred.

Financial liabilities are classified into the following categories:

(i) Financial liabilities measured at amortized cost
Non-derivative financial liabilities are initially recognized at fair value less any directly attributable transaction costs. Subsequent to initial recognition, these liabilities are measured at amortized cost using the effective interest method.

The Corporation currently classifies its accounts payable and other payables, long-term loans and borrowings and the lease obligations recognized in other long-term liabilities as liabilities measured at amortized cost.

The Corporation owns and operates certain projects in the U.S. under tax equity structures to finance the construction of solar and wind projects. Such structures are designed to allocate renewable tax incentives, such as investment tax credits ("ITCs"), production tax credits ("PTCs") and accelerated tax depreciation, to tax equity investors. Generally, tax equity structures grant the tax equity investors the majority of the project's U.S. taxable earnings and renewable tax incentives, along with a smaller portion of the projects' cash flows, until they achieve an agreed-upon after-tax investment return (the "Flip Point"). The Flip Point dates are generally dependent on the projects' respective performance, however, from time to time, the Flip Point dates may be contractually determined. At all times, both before and after the projects' Flip Point, the Corporation retains control over the projects financed with a tax-equity structure. Subsequent to the Flip Point, the Corporation receives the majority of the project's taxable earnings and renewable tax incentives. In accordance with the substance of the contractual agreements, the amounts paid by the tax equity investors for their equity stakes are classified as loans and borrowings on the consolidated statements of financial position until the respective Flip dates of the projects. Subsequent to the Flip Point, the tax investor's equity investments will be accounted for as non-controlling interests. The amortized cost of the tax equity financing is generally comprised of the following elements:

Elements affecting amortized cost of the tax equity financing	Description
Production tax credits (PTCs)	Allocation of PTCs to the tax equity investor derived from the power generated during the period and recognized in other (income) expenses as incurred
Investment tax credits (ITCs)	Allocation of ITCs to the tax equity investor stemming from the construction activities and recognized as a reduction in the cost of the assets to which they relate
Taxable income (loss), including tax attributes such as accelerated tax depreciation	Allocation of taxable income and other tax attributes to the tax equity investor recognized in other (income) expenses as incurred
Pay-go contributions	Additional cash contributions made by the tax equity investor when the annual production exceeds the contractually determined threshold
Cash distributions	Cash allocation to the tax equity investor

(ii) Financial liabilities measured at fair value
Financial liabilities at fair value are initially recognized at fair value and are re-measured at each reporting date with any changes therein recognized in net earnings unless hedge accounting is used in which case the changes are recognized in other comprehensive income.

The Corporation currently classifies its derivative financial instruments as financial liabilities measured at fair value.

The Corporation derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Financial assets and liabilities are offset and the net amount presented in the consolidated statement of financial position when, and only when, the Corporation has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

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

Level 1: valuation based on quoted prices (unadjusted) in active markets to which the entity has access at the evaluation date 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 Corporation recognizes transfers between levels of the fair value hierarchy at the end of the reporting period during which the change has occurred.

Impairment of financial assets

The Corporation estimates the expected credit losses associated with the financial assets accounted for at amortized cost. The impairment methodology used depends on whether there is a significant increase in the credit risk or not. For trade receivables, the Corporation measures loss allowances at an amount equal to the lifetime expected credit loss (ECL) as allowed by IFRS 9 under the simplified method. The Corporation recognizes in earnings (loss), as an impairment gain or loss, the amount of expected credit losses (or reversal thereof) that is required to adjust the loss allowance at the reporting date to the required amount.

Hedging relationships

The Corporation enters into derivative financial instruments to hedge its market risk exposures. On initial designation of new hedges the Corporation formally documents the relationship between the hedging instruments and hedged items, including the risk management objectives and strategy in undertaking the hedge transaction, together with the methods that will be used to assess the effectiveness of the hedging relationship. The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

For a cash flow hedge of a forecasted transaction, the transaction should be highly probable to occur and should present an exposure to variations in cash flows that could ultimately affect reported net earnings.

Derivatives are recognized initially at fair value, and attributable transaction costs are recognized in net earnings as incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein are accounted for as described below.

Cash flow hedges

When a derivative is designated as the hedging instrument in a hedge of the variability in cash flows attributable to a particular risk associated with a recognized asset or liability or a highly probable forecasted transaction that could affect net earnings, the effective portion of changes in the fair value of the derivative is recognized in other comprehensive income and presented in accumulated other comprehensive income as part of equity. The amount recognized in other comprehensive income is removed and included in net earnings under the same line item in the consolidated statement of earnings as the hedged item, in the same period that the hedged cash flows affect net earnings. Any ineffective portion of changes in the fair value of the derivative is recognized immediately in net earnings. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated or exercised, then hedge accounting is discontinued prospectively. The cumulative gain or loss previously recognized in other comprehensive income remains in accumulated other comprehensive income until the forecasted transaction affects net earnings. If the forecasted transaction is no longer expected to occur, then the balance in accumulated other comprehensive income is recognized immediately in net earnings.

Net investment in foreign operation hedges

The Corporation applies hedge accounting to foreign currency differences arising between the functional currency of the foreign operation and the Corporation’s functional currency (Canadian dollars).

Foreign currency differences arising on the translation of a financial liability designated as a hedge of a net investment in a foreign operation are recognized in other comprehensive income to the extent that the hedge is effective, and are presented within equity in the accumulated other comprehensive income. Any ineffective portion of changes in the hedging instruments is recognized directly in net earnings. When the hedged part of a net investment is disposed of, the relevant amount in accumulated other comprehensive income is transferred to the statement of earnings as part of the profit or loss on disposal.

Embedded derivatives

Derivatives embedded in non-derivative host contracts are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the contracts are not measured at fair value through profit or loss.

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 of the consideration received or receivable, 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.

Revenue recognition

Revenue is recognized as the Corporation satisfies its performance obligation which occurs, upon delivery of electricity at rates provided for under the PPAs entered into with the purchasing utilities, on the merchant market or upon compensations from insurance or suppliers for loss of revenues when it is virtually certain that the claim will be received. Penalties for non-production of electricity are recorded at the time when it is highly probable that the amount will be payable as a reduction of revenues over the remaining term of the energy sales contract.

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 for the first 10 years following commissioning of each facility. The Ashlu Creek (ended in November 2019), Douglas Creek (ended in October 2019), Fire Creek (ended in October 2019), Stokke Creek (ended in October 2019), Tipella Creek (ended in October 2019), Lamont Creek, Upper Stave River, Umbata Falls (ended in May 2018) and Toba Montrose hydro facilities and the Carleton (ended in November 2018) and Dokie wind farms are entitled to the subsidies. As per the PPAs, the Corporation must transfer 75% of the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms subsidies to Hydro-Québec. Gross EcoEnergy subsidies of $6,417 ($9,301 in 2018) are included in revenues and the 75% payable to Hydro-Québec for the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms are included in 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.

Employee benefits

Short-term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid under short-term cash bonus or profit-sharing plans if the Corporation has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

Termination benefits are expensed at the earlier of when the Corporation can no longer withdraw the offer of those benefits and when the Corporation recognizes costs for a restructuring. If benefits are not expected to be settled wholly within 12 months of the reporting date, then they are discounted.

Share-based payment

The Corporation measures equity-settled share 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 share 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.

Performance share plan ("PSP plan")

The Corporation measures equity-settled awards using the fair value method. The 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 shares that will eventually vest and a corresponding liability is recorded. For shares that are forfeited before vesting, the expense that had previously been recognized is reversed. When shares are purchased by the fiduciary on the secondary market, the corresponding fair value is debited to common shares capital. On the vesting date, each performance share right entitles its holder to one common share of the Corporation with all the reinvested dividends accrued thereon from the grant date. When paid, the corresponding fair value is credited from the common share capital against the corresponding liability.

Cash settled share-based payment

Under the Corporation's Deferred Share Unit Plan (the "DSU Plan"), Directors and officers may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation. The Corporation cash-settled share-based payments are measured at fair value at the grant date with a corresponding liability. Until the liability is settled, the fair value of the liability is remeasured at the end of each reporting period and at the date of settlement, with any changes in fair value recognized in earnings (loss). DSUs cannot be redeemed for cash until the Director leaves the Board or the officer leaves the Corporation.

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. 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, 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 rates in effect at 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 (loss). 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. The Corporation also designates a portion of its foreign exchange forwards to hedge its investment in its Euro functional currency foreign operations. Translation gains or losses on the portion of the debt and foreign exchange forwards designated as hedges 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 and foreign exchange forwards 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 these hedges. On a quarterly basis, the Corporation reviews the hedges to ensure that they effectively offset the translation gains or losses arising from its investment in its U.S. and its Euro functional currencies foreign operations.

The exchange rates for the currencies used in the preparation of the consolidated financial statements were as follows:

	Exchange rates as at		Average exchange rates for year	
	December 31, 2019	December 31, 2018	2019	2018
Euro	1.4583	1.5613	1.4856	1.5301
US dollar	1.2988	1.3642	1.3269	1.2958

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

The exchange rates related to the Corporation's Icelandic subsidiary, HS Orka, disposed of on May 23, 2019, were as follows :

	Exchange rates as at		Average exchange rates for years	
	May 23, 2019	December 31, 2018	2019	2018
ISK	0.0109	0.0117	0.0111	0.0120

Income taxes

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

Deferred income taxes are 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 income 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 income 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.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same taxation authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

Earnings (loss) per share

The Corporation presents basic and diluted earnings per share data for its common shares. Basic earnings (loss) per share is calculated by dividing net earnings attributable to common shareholders of the Corporation by the weighted average number of shares outstanding during the period as adjusted by the number of common shares held in trust under the PSP plan.

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

Change in accounting policies

The Corporation has adopted the following new standards and interpretations, with an initial application date of January 1, 2019:

IFRS 16, *Leases*

On January 13, 2016, the IASB issued IFRS 16, *Leases* ("IFRS 16") which provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. It supersedes IAS 17, *Leases* and its associated interpretive guidance. Significant changes were made to lessee accounting with the distinction between operating and finance leases removed and assets and liabilities recognized in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). In contrast, IFRS 16 does not include significant changes to the requirements for lessors. The Corporation adopted this standard retrospectively on January 1, 2019 without restating the figures for the comparative periods, as permitted under the specific transitional provisions in the standard (modified retrospective approach).

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

The initial adoption of IFRS 16 resulted in the recognition of lease liabilities in the consolidated statement of financial position, in relation to leases which had previously been classified as operating leases under the principles of IAS 17, *Leases*, with the recognition of a corresponding right-of-use asset. The lease liabilities were measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate as of January 1, 2019. The weighted average lessee's incremental borrowing rate applied to the lease liabilities on January 1, 2019 was 3.79%.

The right-of-use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to the corresponding lease agreement recognized in the consolidated statement of financial position as at December 31, 2018. There were no onerous lease contracts that would have required an adjustment to the right-of-use assets at the date of initial application.

Upon initial application of IFRS 16, the Corporation has used the following practical expedients permitted by the standard:

- reliance on previous assessments on whether leases are onerous;
- the accounting for operating leases with a remaining lease term of less than 12 months as at January 1, 2019 as short-term leases;
- the exclusion of initial direct costs for the measurement of the right-of-use asset at the date of initial application; and
- the use of hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

A reconciliation of the lease liability as at January 1, 2019 is as follows:

	As at January 1, 2019
Operating lease commitments comprised in the total commitments disclosed as at December 31, 2018	188,983
Discounted using the lessee's incremental borrowing rate at the date of initial application	122,270
Current portion of Lease liability	5,084
Non-current portion of Lease liability	117,186
Lease liability	122,270

The following table shows the effects of the application of IFRS 16 on the segment opening balances on the consolidated statement of financial position as at January 1, 2019:

	Hydroelectric	Wind	Solar	Site development/ Corporate	Total
Current assets					
Prepaid and others	—	(1,640)	(50)	—	(1,690)
Non-current assets					
Right-of-use assets presented in Property, plant and equipment	2,775	56,652	839	63,622	123,888
Current liabilities					
Accounts payable and other payables	—	(72)	—	—	(72)
Lease liabilities presented in other liabilities	50	2,410	12	2,612	5,084
	50	2,338	12	2,612	5,012
Non-current liabilities					
Lease liabilities presented in other liabilities	2,725	52,674	777	61,010	117,186

The impacts of the application of IFRS 16 on the consolidated statement of earnings are a decrease in operating expenses (formerly – operating land leases) and general and administrative expenses (formerly – office space operating leases), offset by an increase in finance costs (originating from the lease liabilities) and depreciation (originating from the corresponding right-of-use assets).

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

Tax equity investments

During the year ended December 31, 2019, the Corporation proceeded to a change in the method of accounting for tax equity financing, as previously recorded as an element of equity, which resulted in a reclassification of the tax equity financing as financial liabilities. The change was applied during the fourth quarter of 2019. Comparative figures have been adjusted to conform to the current year's presentation. The change resulted in the following reclassifications:

Consolidated Statements of Financial Position

	As at December 31 2018
Property, plant and equipment	(12,265)
Investments in joint ventures and associates	47,139
Total assets	34,874
Current portion of long-term loans and borrowings and other liabilities	(208)
Long-term loans and borrowings	(503)
Deferred tax liabilities	53,109
Total liabilities	52,398
Deficit	(1,552)
Accumulated other comprehensive income	1,021
Non-controlling interests	(16,993)
Total shareholders' equity	(17,524)
Total liabilities and shareholders' equity	34,874

Consolidated Statements of Earnings

	Year ended December 31 2018
Depreciation	(670)
Finance costs	186
Other net revenues	(764)
Share of earnings of joint ventures and associates	(22,248)
Earnings before income taxes	(23,496)
Deferred income tax expense	23,496
Net earnings and net earnings from continuing operations	—
Attributable to:	
Owners of the parent	(1,552)
Non-controlling interests	1,552

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

Amendments to IFRS 9, *Financial Instruments (Interest rate benchmark reform)*

On September 26, 2019, the IASB issued amendments for some of its requirements for hedge accounting in IFRS 9, *Financial Instruments* in relation to Phase 1 of IBOR Reform and its Effects on Financial Reporting project. The amendments are effective for periods beginning on or after January 1, 2020, with early adoption permitted. The Corporation has applied the interest rate benchmark reform amendments retrospectively to hedging relationships that existed at January 1, 2019 or were designated thereafter and that are directly affected by the interest rate benchmark reform. These amendments also apply to the gain or loss recognized in OCI that existed at January 1, 2019.

3. USE OF JUDGMENTS AND ESTIMATES

Significant estimates and assumptions

The preparation of consolidated financial statements in conformity with IFRS requires management to make estimates and assumptions that 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 periods, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment, intangible assets, project development costs and goodwill, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives, effectiveness of hedging relationships and classification of structured entities. 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 unless hedge accounting is used, in which case the changes are recognized in comprehensive income. Fair values of some financial instruments are estimated by using valuation techniques that require several assumptions such as interest rate, credit spread, exchange rates, forward prices and other.

Useful lives of property, plant and equipment and Intangible assets

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

Impairment of non-financial assets

The Corporation makes a number of estimates when calculating the recoverable amount of an asset or a cash-generating unit using value in use calculations based on discounted future cash flows. Future cash flows may be influenced by a number of estimates such as electricity production, duration of the projects, selling prices, costs to operate, capital expenditures, growth rate and the discount rate. The likelihood of being able to develop future projects is also assessed in respect of the competitive business environment and the willingness expressed by the governmental authorities to procure additional sources of energy.

Business acquisition fair value

The Corporation makes a number of estimates when determining the acquisition date fair values of consideration transferred, assets acquired and liabilities assumed in a business acquisition. Fair values are estimated using valuation techniques that require several assumptions such as future production, earnings and expenses and discount rates.

Determining control, joint control or significant influence of an investee

The determination of whether the Corporation has control, joint control or significant influence over an investee requires the Corporation to make assumptions and judgments in evaluating the classification requirements.

Based on the contractual arrangements between the Corporation and the other respective partner, and the fact that the Corporation owns more than 50% of the economic interest, the Corporation concluded that it has control over Kwoiek Creek Resources L.P., Mesgi'g Ugju's'n (MU) Wind Farm L.P., Kokomo Solar 1, LLC, Spartan PV 1, LLC, Foard City Wind, LLC and Phoebe Energy Project, LLC.

Asset retirement obligations

The Corporation makes a number of estimates when calculating fair value of the asset retirement obligations that represent the present value of future remediation costs for various projects. Estimates for these costs are dependent on labour costs, the effectiveness of remedial and restoration measures, inflation rates, discount rates that reflect a current market assessment of the time value of money and the risk specific to the obligation, and the timing of the outlays.

Hedging

The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

The Corporation may, from time to time, enter into long-term power hedge agreements that require critical judgments to determine the fair value and the designation of the long-term power hedge. As part of the designation of the power hedges as cash flow hedges, the Corporation makes certain judgments regarding the probability of future events. As part of determining fair value, the Corporation makes certain assumptions, estimates and judgments regarding future events. Unobservable forecast future power prices are inherently subjective and impact the change in fair value recognized in the consolidated statement of earnings and the consolidated statement of comprehensive loss.

4. BUSINESS ACQUISITIONS

a. Acquisition of our partner's interest in the Cartier Wind Farms

On October 24, 2018, the Corporation completed the acquisition of TransCanada's 62% interest in five wind farms in Quebec's Gaspé peninsula, namely Baie-des-Sables, Carleton, Gros-Morne, L'Anse-à-Valleau and Montagne Sèche (the "Cartier Wind Farms"), and its 50% interest in the operating entities of the Cartier Wind Farms (the "Cartier Operating Entities"), for a total consideration of $621,471.

The Corporation previously owned a 38% interest in the Cartier Wind Farms and a 50% interest in the Cartier Operating Entities which were accounted for as joint operations as they represented rights to the assets and obligations for the liabilities of the wind farms. After the acquisition, the Corporation owns 100% of Cartier Wind Farms and 100% of the Cartier Operating Entities. Upon acquisition, the Corporation did not remeasure its previously held interest in the Cartier Wind Farms.

Concurrent with the closing of the acquisition, Innergex has obtained two short-term credit facilities of $400,000 and $228,000 respectively to cover the purchase price and transaction costs in their entirety.

The Cartier acquisition added an additional gross installed capacity of 365 MW to the Corporation's portfolio.

The following table reflects the final acquisition accounting and the fair value of the net assets acquired:

	Final acquisition accounting
Cash and cash equivalents	1,414
Accounts receivable	6,653
Prepaid and others	2,586
Property, plant and equipment	575,995
Intangible assets	73,162
Goodwill	11,165
Accounts payable and other payables	(4,722)
Other liabilities	(33,617)
Deferred tax liabilities	(11,165)
Net assets acquired	621,471

Goodwill is not deductible for tax purposes.

The transaction costs relating to this acquisition have been expensed in accordance with IFRS 3 (see note 8).

The revenues and net earnings of the acquired interest in the facilities since October 24, 2018 included in the consolidated statement of earnings are $19,975 and $4,675, respectively for the 69-day period ended December 31, 2018.

Had the acquisition taken place on January 1, 2018, the consolidated revenues and net earnings for the period from January 1, 2018 to October 23, 2018 would have been $67,016 and $4,381 higher, respectively.

b. Acquisition of Alterra Power Corp.

On February 6, 2018, Innergex acquired all of the issued and outstanding common shares of Alterra Power Corp. ("Alterra").

The Innergex common shares issuable to Alterra shareholders with the transaction represent an ownership of approximately 18% of the combined corporation. One member of the Board of Directors of Alterra joined the Board of Directors of Innergex at the closing of the transaction.

The total purchase price of $450,865 for Alterra was comprised of a cash consideration of $120,258 and the issuance of 24,327,225 common shares of the Corporation at a price of $13.59, for a value of $330,607.

Alterra and its subsidiaries are engaged in the development, construction and operation of renewable energy projects. As at February 6, 2018, Alterra's operating facilities consisted of a 53.9% net interest in two geothermal power plants in Iceland

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

("Svartsengi" and "Reykjanes"), and an indirect 30% interest in Blue Lagoon, which operated the Blue Lagoon geothermal spa in Iceland ("Blue Lagoon"). It also consisted of a 40% net interest in two run-of-river hydro power plants ("Toba Montrose"), a 25.5% net interest in a wind farm ("Dokie"), a 51% net interest in a run of river hydro power plant ("Jimmie Creek") in British Columbia, a 50% net interest in a wind farm ("Shannon") located in Texas, a 90% net interest in a solar project ("Kokomo") located in Indiana and a 100% net interest in a solar project ("Spartan") located in Michigan.

The Alterra acquisition added an additional gross installed capacity of 840 MW to the Corporation's portfolio.

The following table reflects the final acquisition accounting and the fair value of the net assets acquired:

	Final acquisition accounting
Cash and cash equivalents	7,218
Restricted cash and short-term investments	5,893
Accounts receivable	17,745
Prepaid and others	3,925
Reserve accounts	873
Property, plant and equipment	514,837
Intangible assets	240,009
Project development costs	19,298
Investments in joint ventures and associates	447,130
Goodwill	59,288
Other long term assets	16,281
Accounts payable and other payables	(40,747)
Income tax liabilities	(1,126)
Long-term loans and borrowings	(326,136)
Derivative financial instruments	(30,282)
Other liabilities	(47,972)
Deferred tax liabilities	(138,833)
Non-controlling interests	(296,536)
Net assets acquired	450,865

Goodwill is not deductible for tax purposes.

The transaction costs relating to this acquisition have been expensed in accordance with IFRS 3 (see note 8).

Non-controlling interest are measured at their proportionate share of the acquiree's identifiable net assets.

The revenues and net earnings of the facilities since February 6, 2018 included in the consolidated statement of earnings are $97,823 and $4,936, respectively for the 329-day period ended December 31, 2018.

Had the acquisition taken place on January 1, 2018, the consolidated revenues and net earnings for the period from January 1, 2018 to February 5, 2018 would have been $11,471 and $4,578 higher, respectively.

c. Acquisition of the assets of Phoebe

On July 2, 2018, Innergex acquired a 250 MW_{AC}/315 MW_{DC} photovoltaic solar project located in Winkler County, Texas. Full notice to proceed with construction was also issued on July 2, 2018 and full commercial operation has been reached in the fourth quarter of 2019. The project is also eligible to receive a federal Investment Tax Credit (ITC) equal to approximately 30% of the project's capital costs. The ITC will be mostly allocated to the Tax Equity Investor. The Phoebe project will sell 100% of its output to the Electric Reliability Council of Texas ("ERCOT") power grid and receive a fixed price on 89% of its energy produced under a 12-year power purchase agreement.

The total purchase price for Phoebe was US$100,191 ($131,791) and was comprised entirely of cash consideration.

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

The following table reflects the fair value of the assets acquired:

	Assets acquired	
	US$	$
Property, plant and equipment	84,043	110,550
Derivative financial instruments	16,148	21,241
Total assets acquired	100,191	131,791

The Corporation determined that, at the acquisition date, Phoebe constituted a group of assets rather than a business as defined in IFRS 3, and has accounted for the acquisition as an asset acquisition.

5. DISCONTINUED OPERATIONS

In 2019, the Corporation sold its wholly-owned subsidiary Magma Energy Sweden A.B., which owned an equity interest of approximately 53.9% in HS Orka hf ("HS Orka"), to Jarðvarmi slhf for a sale price of US$297,868 ($401,524). HS Orka represented both the Corporation's Icelandic geographic segment and geothermal operating segment.

The following table summarizes the details of the sale of discontinued operations:

	Total CAD
Consideration received, net of transaction costs:	
Cash consideration (US$299,910)	404,219
Consideration paid for working capital adjustment (US$2,042)	(2,695)
Transaction costs	(6,634)
Total disposal consideration, net of transaction costs	394,890
Carrying amount of net assets sold	331,147
Gain on sale before reclassification of foreign currency translation differences	63,743
Reclassification of foreign currency translation differences	46,015
Gain on sale	17,728

The carrying amounts of assets and liabilities as at the date of sale:

	As at May 23, 2019
Current assets	37,039
Non-current assets	855,734
Total assets	892,773
Current liabilities	71,976
Non-current liabilities	228,804
Total liabilities	300,780
Equity attributable to owners of the parent	331,147
Non-controlling interests	260,846
Total shareholders' equity	591,993
Total liabilities and shareholders' equity	892,773

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

The following table summarizes the net earnings from discontinued operations:

	Year ended December 31, 2019	Period of 329 days ended December 31, 2018
Revenues	40,006	95,198
Expenses	39,677	105,512
Share of earnings of joint ventures and associates	(3,718)	(8,762)
Earnings (loss) before income taxes	4,047	(1,552)
Recovery of income taxes	(40)	(1,055)
Net earnings from discontinued operations before the following:	4,087	(497)
Gain on sale of the subsidiary	(17,728)	—
Net earnings from discontinued operations	21,815	(497)
Other comprehensive income (loss) from discontinued operations	3,928	(36,838)
Total comprehensive income (loss) from discontinued operations	25,743	(37,335)
Net earnings (loss) from discontinued operations attributable to:		
Owners of the parent	19,682	(685)
Non-controlling interests	2,133	188
	21,815	(497)
Total comprehensive income (loss) from discontinued operations attributable to:		
Owners of the parent	42,832	(24,213)
Non-controlling interests	(17,089)	(13,122)
	25,743	(37,335)
Net earnings (loss) per share from discontinued operations		
Basic net earnings (loss) per share ($)	0.15	(0.01)
Diluted net earnings (loss) per share ($)	0.15	(0.01)

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

6. EXPENSES BY NATURE

Operating, general and administrative and prospective projects expenses, as reported in the consolidated statements of earnings, have been grouped by nature of expenses as follows:

	Year ended December 31	
	2019	2018
Operation and maintenance	55,276	44,186
Salaries and benefits	38,109	31,907
Property taxes and royalties	28,104	30,458
Other expenses	6,635	4,363
Professional fees	6,248	4,604
Insurance	6,046	4,632
Prospective expenses	5,344	7,640
Administrative expenses	2,105	1,449
Total of Operating, General and Administrative and Prospective Projects	147,867	129,239

Depreciation of $153,617 ($111,083 in 2018) and amortization of $40,962 ($40,173 in 2018) recorded in the consolidated statements of earnings are mainly related to operating expenses incurred to generate revenues.

7. FINANCE COSTS

	Year ended December 31	
	2019	2018
Interest expense on long-term corporate and project loans	181,586	165,712
Interest expense on convertible debentures	12,014	8,193
Interest expense on tax equity investors financing	9,319	186
Interest on lease liabilities	2,925	—
Inflation compensation interest	5,171	6,798
Amortization of financing fees	8,887	4,582
Accretion of long-term loans and borrowings	2,880	2,367
Accretion expenses on other liabilities	4,496	3,265
Other	4,488	4,731
	231,766	195,834

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

8. OTHER NET (REVENUES) EXPENSES

	Year ended December 31	
	2019	2018
Tax attributes allocated to tax equity investors	(88,402)	(764)
Production tax credits	(11,238)	—
Other net revenues	(4,613)	(1,963)
Gain on debt modifications (Note 21)	(2,883)	—
Restructuring costs	1,823	—
Loss on disposal of property, plant and equipment	670	538
Transaction costs related to business combinations (Note 4)	—	8,280
Realized loss on derivative financial instruments	—	6,092
	(104,643)	12,183

Tax attributes allocated to tax equity investors

In tax equity structures, a portion of the tax attributes generated by a renewable project, such as taxable income (loss), including accelerated tax depreciation under the U.S. Modified Accelerated Cost Recovery System ("MACRS"), are allocated to the tax equity investors and applied against the related tax equity financing as principal repayment. During the year ended December 31, 2019, tax attributes allocated to the tax equity investors and applied as principal payment against the tax equity financing totalled $88,402 and relate to the Foard City wind and the Phoebe solar projects commissioned during the year, which was subject to accelerated tax depreciation under the MACRS, as well as the Kokomo and Spartan solar projects (2018 - $764 related to the Kokomo and Spartan solar projects).

Production tax credits

Certain projects are eligible to receive U.S. renewable tax incentives such as PTCs, which are earned as production occurs. In tax equity structures, the portion of these tax attributes which is allocated to the tax equity investors is applied against the related tax equity financing as principal repayment. During the year ended December 31, 2019, PTCs earned and applied as principal payment against the tax equity financing totalled $11,238 and relate to the Foard City wind project commissioned during the year (2018 - nil).

Restructuring costs

During the third quarter of 2019, the Corporation committed to a plan to restructure its accounting department, under which the accounting functions are to be centralized in the head office to improve organizational efficiency (the “Plan”). Following the announcement of the Plan to its employees, the Corporation recognized a provision of $1,823 for restructuring costs, comprised mainly of employee termination benefits and consulting fees. As at December 31, 2019, the restructuring activities were ongoing and an amount of $1,237 has been incurred to date. The reorganization is expected to be completed by the first quarter of 2020.

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

9. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

9.1 Details of material joint ventures and associates

Joint ventures and associates	Principal activity	Place of creation and principal place of operation	Proportion of ownership interest and voting rights held by the Corporation	
			December 31, 2019	December 31, 2018
Energia Llaima	Own and operate three hydroelectric facilities and a solar facility	Chile	50%	50%
Toba Montrose	Own and operate two hydroelectric facilities	British Columbia	40%	40%
Shannon	Own and operate a wind farm	Texas	50%	50%
Flat Top	Own and operate a wind farm	Texas	51% [1]	51%
Dokie	Own and operate a wind farm	British Columbia	25.5%	25.5%
Jimmie Creek	Own and operate a hydroelectric facility	British Columbia	50.99% [1]	50.99%
Umbata Falls	Own and operate a hydroelectric facility	Ontario	49%	49%
Viger-Denonville	Own and operate a wind farm	Quebec	50%	50%
Blue Lagoon (see Note 5)	Own and operate a geothermal spa	Iceland	—%	30%
Innavik	Develop and construct a hydroelectric facility	Quebec	50%	—%

1. The Corporation doesn't consolidate these entities as it doesn't control the decision making.

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

The summarized financial information below represents amounts shown in the joint ventures' and associates' financial statements prepared in accordance with IFRS adjusted for fair value adjustments at acquisition and differences in accounting policies.

Summary Statements of Earnings and Comprehensive Income (Loss)

	Year ended December 31, 2019								
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Innavik
Revenues	52,301	70,643	19,257	24,405	36,460	21,429	8,223	11,293	—
Operating, general and administrative expenses	24,360	16,360	10,799	13,023	8,932	4,447	1,624	2,163	3,620
	27,941	54,283	8,458	11,382	27,528	16,982	6,599	9,130	(3,620)
Finance costs	11,948	27,579	14,659	17,842	9,925	9,380	2,121	3,309	—
Production tax credits	—	—	(22,646)	(28,430)	—	—	—	—	—
Tax attributes allocated to tax equity investors	—	—	1,119	(10,890)	—	—	—	—	—
Other net expenses (revenues)	6,413	(666)	359	(69)	(703)	769	(113)	(93)	—
Depreciation and amortization	14,389	17,716	13,997	14,687	10,496	4,742	4,010	2,712	—
Unrealized net (gain) loss on financial instruments	—	(1,001)	(3,886)	(40,785)	—	—	595	(459)	—
Provision for income taxes	3,927	—	—	—	—	—	—	—	—
Net (loss) earnings	(8,736)	10,655	4,856	59,027	7,810	2,091	(14)	3,661	(3,620)
Other comprehensive loss	—	(3,503)	—	—	—	—	—	(941)	—
Total comprehensive (loss) income	(8,736)	7,152	4,856	59,027	7,810	2,091	(14)	2,720	(3,620)
Net (loss) earnings attributable to Innergex	(3,397)	4,262	2,428	30,104	1,992	1,066	(7)	1,831	(1,810)
Total comprehensive (loss) income attributable to Innergex	(3,397)	2,861	2,428	30,104	1,992	1,066	(7)	1,360	(1,810)

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

Summary Statements of Earnings and Comprehensive Income (Loss)

	Year ended December 31, 2018									
	Energía Llaima (181-day period)	Toba Montrose (329-day period)	Shannon (329-day period)	Flat Top (329-day period)	Dokie (329-day period)	Jimmie Creek (329-day period)	Umbata Falls	Viger-Denonville	Blue Lagoon (Note 5)	Others
Revenues	30,739	65,435	13,934	15,057	31,610	19,166	9,459	11,724	172,094	—
Operating, general and administrative expenses	13,855	14,913	8,326	9,750	7,655	3,202	910	2,056	116,793	—
	16,884	50,522	5,608	5,307	23,955	15,964	8,549	9,668	55,301	—
Finance costs	6,043	25,409	13,582	14,986	9,659	8,638	2,257	3,423	1,373	—
Production tax credits	—	—	(19,313)	(18,581)	—	—	—	—	—	—
Tax attributes allocated to tax equity investors	—	—	(3,650)	(45,820)	—	—	—	—	—	—
Other net (revenues) expenses	(3,588)	(495)	(785)	90	360	672	(81)	(72)	1,069	—
Depreciation and amortization	7,406	14,988	8,798	10,447	11,327	4,380	4,011	2,517	13,656	—
Unrealized net loss (gain) on financial instruments	—	1,135	(12,454)	(6,315)	—	—	(715)	(768)	—	—
Provision for income taxes	1,557	—	—	—	—	—	—	—	10,025	—
Net earnings	5,466	9,485	19,430	50,500	2,609	2,274	3,077	4,568	29,178	—
Other comprehensive (loss) income	—	—	—	—	—	—	—	(180)	(20,353)	31
Total comprehensive income	5,466	9,485	19,430	50,500	2,609	2,274	3,077	4,388	8,825	31
Continuing operations:										
Net earnings attributable to Innergex	2,715	3,794	9,715	25,755	665	1,160	1,508	2,284	—	—
Total comprehensive income attributable to Innergex	2,715	3,794	9,715	25,755	665	1,160	1,508	2,194	—	31
Discontinued operations:										
Net earnings attributable to Innergex	—	—	—	—	—	—	—	—	8,762	—
Total comprehensive income attributable to Innergex	—	—	—	—	—	—	—	—	2,650	—

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

Summary Statements of Financial Position

	As at December 31, 2019								
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Innavik
Current assets	67,728	27,427	11,435	7,090	19,116	8,699	2,199	2,407	1,795
Non-current assets	535,024	735,872	374,717	507,887	234,607	226,801	53,101	53,101	15,571
	602,752	763,299	386,152	514,977	253,723	235,500	55,300	55,508	17,366
Current liabilities	17,787	17,921	25,447	32,884	10,897	5,141	2,782	45,859	17,385
Non-current liabilities	236,700	549,785	177,929	216,986	146,355	165,119	36,612	7,923	3,600
Partner's equity interest (deficit)	284,532	195,593	182,776	265,107	96,471	65,240	15,906	1,726	(3,619)
Non-controlling interests	63,733	—	—	—	—	—	—	—	—
	602,752	763,299	386,152	514,977	253,723	235,500	55,300	55,508	17,366

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

	For the year ended December 31, 2019											
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Blue Lagoon (Note 5)	Innavik	Others	Total
Balance January 1, 2019	154,299	80,976	95,052	113,355	24,521	36,535	9,406	1,453	136,228	—	87	651,912
Business disposal	—	—	—	—	—	—	—	—	(136,228)	—	—	(136,228)
Increase in investment	—	—	—	—	—	—	—	—	—	—	3	3
Share of (loss) earnings	(3,397)	4,262	2,428	30,104	1,992	1,066	(7)	1,831	—	(1,810)	—	36,469
Share of other comprehensive loss	—	(1,401)	—	—	—	—	—	(471)	—	—	—	(1,872)
Foreign currency translation differences	(8,636)	—	(4,379)	(5,872)	—	—	—	—	—	—	—	(18,887)
Distributions received	—	(5,600)	(1,713)	(2,382)	(1,913)	(4,335)	(1,605)	(1,950)	—	—	—	(19,498)
Balance December 31, 2019	142,266	78,237	91,388	135,205	24,600	33,266	7,794	863	—	(1,810)	90	511,899

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

	As at December 31, 2018								
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Blue Lagoon (Note 5)
Current assets	64,598	22,229	9,795	13,682	14,203	10,617	3,769	2,950	23,519
Non-current assets	570,472	762,471	388,332	479,499	225,788	231,632	56,872	53,757	538,975
	635,070	784,700	398,127	493,181	239,991	242,249	60,641	56,707	562,494
Current liabilities	14,897	15,029	30,828	50,378	10,014	4,607	3,422	4,151	38,673
Non-current liabilities	244,620	567,230	177,195	220,538	133,815	165,990	38,023	49,652	70,180
Partner's equity interest	308,598	202,441	190,104	222,265	96,162	71,652	19,196	2,904	453,641
Non-controlling interests	66,955	—	—	—	—	—	—	—	—
	635,070	784,700	398,127	493,181	239,991	242,249	60,641	56,707	562,494

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

	For the year ended December 31, 2018										
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Blue Lagoon (Note 5)	Others	Total
Balance January 1, 2018	—	—	—	—	—	—	9,688	1,272	—	51	11,011
Business acquisitions	—	84,182	80,148	79,629	24,366	37,670	—	—	141,135	—	447,130
Increase in investment	144,694	—	—	2,520	—	—	—	—	—	5	147,219
Share of earnings	2,715	3,794	9,715	25,755	665	1,160	1,508	2,284	—	—	47,596
Share of earnings reclassified as discontinued operations	—	—	—	—	—	—	—	—	8,762	—	8,762
Share of other comprehensive income (loss)	—	—	—	—	—	—	—	(90)	—	31	(59)
Foreign currency translation differences	6,890		7,391	8,683	—	—	—	—	—	—	22,964
Share of other comprehensive (loss) reclassified as discontinued operations	—	—	—	—	—	—	—	—	(6,112)	—	(6,112)
Distributions received	—	(7,000)	(2,202)	(3,232)	(510)	(2,295)	(1,790)	(2,013)	(7,557)	—	(26,599)
Balance December 31, 2018	154,299	80,976	95,052	113,355	24,521	36,535	9,406	1,453	136,228	87	651,912

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

Shannon

The Corporation holds a 50% interest in the Shannon wind facility, with the remaining 50% interest held by third parties.

On June 29, 2015, Shannon entered into a long-term power hedge covering the period from June 1, 2016 to May 31, 2029. The power hedge provides for Shannon to receive a fixed dollar per MWh for a fixed quantity of power.

The initial amount of the tax equity financing upon the acquisition of Alterra on February 6, 2018 represents the fair value of US$144,534 ($181,102). Subsequently, the carrying amount is reduced by the allocation of U.S. renewable tax incentives (PTCs), taxable income and cash distributions paid to date offset by the effective interest expense. The Shannon wind project is eligible to receive PTCs related to its wind power generation for the first ten years of the project's operations (until 2025). The amortized cost of the tax equity financing as at December 31, 2019 was $157,204 (December 31, 2018 - $179,088) and the liability will be fully repaid at the Flip Point, which is expected to occur in 2028.

The tax equity investors' taxable income (losses), PTCs and cash distributions allocations are detailed in the table below. After the Flip Point, the Shannon tax equity investors will retain a 5% financial interest in the project which will be accounted for as non-controlling interests.

	Tax Equity Investors
Taxable income (losses) and PTCs	99.0%
Cash distributions	64.3% [1]

1. Cash distributions are based on a quarterly test measurement of cumulative generation for the project since commercial operations date. Lower production could result in a higher cash allocation to the tax equity investor or a change to the Flip Point. The percentage provided is for the year ended December 31, 2019.

Tax equity investors in U.S. wind projects generally require sponsor guarantees as a condition to their investment. To support the tax equity investment in Shannon, Alterra Power Corp., a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters which are substantially under its control, and are very unlikely to occur.

Flat Top

The Corporation holds a 51% interest in the Flat Top wind facility, with the remaining 49% interest held by third parties. The wind farm began commercial operation on March 23, 2018.

On May 24, 2017, Flat Top entered into a long-term power hedge covering the period from August 1, 2018 to July 31, 2031. The power hedge provides for Flat Top to receive a fixed dollar per MWh for a fixed quantity of power.

The initial fair value of the tax equity financing represents the proceeds received on March 27, 2018 from the tax equity investor in exchange for Class A shares of the project company, aggregating to US$211,300 ($274,035). Subsequently, the carrying amount is reduced by the allocation of U.S. renewable tax incentives (PTCs), taxable income and cash distributions paid to date offset by the effective interest expense. The Flat Top wind project is eligible to receive PTCs related to its wind power generation for the first ten years of the project's operations (until 2028). The amortized cost of the tax equity financing as at December 31, 2019 was $197,121 (December 31, 2018 - $234,756) and the liability will be fully repaid at the Flip Point, which is expected to occur in 2028.

The tax equity investors' taxable income (losses), PTCs and cash distributions allocations are detailed in the table below. After the Flip Point, the Flat Top tax equity investors will retain a 5% financial interest in the project which will be accounted for as non-controlling interests.

	Tax Equity Investors
Taxable income (losses) and PTCs	99.0%
Cash distributions	22.0% [1]

1. Cash distributions are based on a quarterly test measurement of cumulative generation for the project since commercial operations date. Lower production could result in a higher cash allocation to the tax equity investor or a change to the Flip Point. The percentage provided is for the year ended December 31, 2019.

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

Tax equity investors in U.S. wind projects generally require sponsor guarantees as a condition to their investment. To support the tax equity investment in Flat Top, Alterra Power Corp., a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters which are substantially under its control, and are very unlikely to occur.

9.2 Commitments of joint ventures and associates

As at December 31, 2019, the Corporation's share of the expected schedule of commitment payments for joint ventures and associates are as follows:

Year of expected payment	Under 1 year	1 to 5 years	Thereafter	Total
Purchase obligations	8,062	44,079	109,581	161,722

10. DERIVATIVE FINANCIAL INSTRUMENTS

The following tables show a reconciliation from the opening balances to the closing balances for the derivative financial instruments (refer to Note 28 for financial risk management and fair value disclosures):

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging instruments (Level 2)	Power and basis hedges (Level 3)	Inflation provisions (Level 3)	Embedded derivatives (Level 2)	Total
As at January 1, 2019	(32,129)	(53,409)	(4,849)	982	(46,409)	(135,814)
Realized financial instruments	—	4,145	11,905	—	—	16,050
Recognized in consolidated statement of earnings[1]	5,917	3,619	(42,145)	(982)	—	(33,591)
Variation in fair value of derivative financial instruments recognized in other comprehensive income	1,943	(39,318)	63,006	—	—	25,631
Net foreign exchange differences	—	1,427	(160)	—	—	1,267
Business disposal (Note 5)	—	—	—	—	46,409	46,409
As at December 31, 2019	(24,269)	(83,536)	27,757	—	—	(80,048)

1. The $49,933 unrealized net loss on financial instruments recognized in the consolidated statement of earnings includes a loss of $16,342 resulting from an intragroup loan. On consolidation, although the intragroup loan is eliminated from the consolidated statement of financial position, the related exchange loss is recognized in the consolidated statement of earnings.

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

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging instruments (Level 2)	Power hedge (Level 3)	Inflation provisions (Level 3)	Embedded derivatives (Level 2)	Total
As at January 1, 2018	(17,294)	(46,710)	—	1,735	—	(62,269)
Derivatives acquired on business acquisitions (Note 4)	—	913	21,241	—	(31,195)	(9,041)
Recognized in consolidated statement of earnings[1]	(13,489)	14,143	—	(753)	—	(99)
Recognized in consolidated statement of earnings as discontinued operations	—	—	—	—	(16,863)	(16,863)
Variation in fair value of derivative financial instruments recognized in other comprehensive income	(1,346)	(21,644)	(26,353)	—	—	(49,343)
Net foreign exchange differences	—	(111)	263	—	1,649	1,801
As at December 31, 2018	(32,129)	(53,409)	(4,849)	982	(46,409)	(135,814)

1. The $12,958 unrealized net gain on financial instruments recognized in the consolidated statement of earnings includes a gain of $13,057 resulting from an intragroup loan. On consolidation, although the intragroup loan is eliminated from the consolidated statement of financial position, the related exchange loss is recognized in the consolidated statement of earnings.

Reported in the consolidated statements of financial position:

As at	December 31, 2019	December 31, 2018
Current assets	5,419	2,370
Non-current assets	78,251	9,817
Current liabilities	(51,093)	(29,999)
Non-current liabilities	(112,625)	(118,002)
	(80,048)	(135,814)

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

11. PROVISION FOR INCOME TAXES

a. Income taxes recognized in statements of earnings

	December 31, 2019	December 31, 2018
Current income taxes		
Current tax expense in respect of the current year	16,830	8,528
Adjustments recognized in the current year in relation to the current tax expense of prior years	15	(7)
	16,845	8,521
Deferred income taxes		
Deferred tax expense recognized in the current year	103,828	19,677
Decrease in deferred income tax rates	(1,357)	(558)
Adjustments recognized in the current year in relation to the deferred tax of prior years	(465)	(395)
	102,006	18,724
Provision for income taxes recognized in the current year	118,851	27,245

The following table summarizes the reconciliation of the income tax expense calculated at the Canadian statutory income tax rate and the income tax expense recognized in statements of earnings.

	December 31, 2019	December 31, 2018
Earnings before income taxes	65,825	53,460
Canadian statutory income tax rate	26.6%	26.6%
Income taxes expenses calculated at the statutory rate	17,509	14,220
Items affecting the statutory rate		
Non-taxable income	(9,064)	(4,262)
Effect of previously unrecognized tax losses balances used in the year	(2,599)	(355)
Amounts attributable to Tax Equity Investors	131,026	26,406
Change in deferred tax assets not recognized	(12,307)	1,862
Income taxable at a different rate than the Canadian statutory rate	(3,576)	(5,657)
Decrease in deferred income tax rates	(1,357)	(558)
Increase (decrease) in taxable temporary differences in relation to investments in subsidiaries and in joint ventures	541	(2,019)
Tax on dividends on preferred shares	166	164
Adjustments recognized in the current year in relation to the current tax of prior years	15	(7)
Adjustments recognized in the current year in relation to the deferred tax of prior years	(465)	(395)
Income tax on earnings allocated to minority interests on non-taxable entities	(839)	(2,025)
Others	(199)	(129)
Provision for income taxes recognized in the current year	118,851	27,245

The tax rate used for 2019 and 2018 reconciliations above is the average combined corporate tax rate payable by corporate entities in Canada on taxable profits under federal and provincial tax laws.

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

b. Income taxes recognized in other comprehensive income

	December 31, 2019	December 31, 2018
Deferred income taxes		
Foreign currency translation differences for foreign operations	—	(205)
Foreign exchange gain (loss) on the designated hedges on the net investments in foreign operations	540	(645)
Change in fair value of financial instruments designated as cash flow hedges	4,079	(13,577)
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges	(1,488)	3,287
Share of non-controlling interests in change in fair value of hedging instruments	(934)	(150)
Total income taxes recognized directly in other comprehensive income	2,197	(11,290)

c. Deferred income tax balances

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

	December 31, 2019	December 31, 2018
Assets	30,264	16,465
Liabilities	(428,793)	(379,013)
	(398,529)	(362,548)

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

	As at January 1, 2019	Recognized in statement of earnings	Recognized in other comprehensive loss	Discontinued operations	Recognized directly in equity	Net exchange differences	As at December 31, 2019
Deferred income tax assets (liabilities) in relation to:							
Property, plant and equipment	(206,562)	(148,033)	—	27,913	—	2,599	(324,083)
Intangible assets	(183,994)	13,228	—	18,094	—	(5,605)	(158,277)
Project development costs	1,927	3,097	—	18,085	—	(80)	23,029
Investments into subsidiaries and in joint ventures and associates	(135,864)	(2,986)	(10,131)	24,520	—	2,849	(121,612)
Non-repatriated income from foreign subsidiaries	(1,027)	60	—	—	—	(1,312)	(2,279)
Derivative financial instruments	69,083	(16,711)	8,480	(7,987)	—	728	53,593
Long-term debt	2,246	3,212	(546)	(3,576)	—	(158)	1,178
Capitalized investment tax credits	1,372	13,026	—	—	—	(526)	13,872
Convertible debentures	(928)	(239)	—	—	(195)	—	(1,362)
Other liabilities	3,701	1,632	—	(2,965)	—	(11)	2,357
Financing fees	(5,855)	(1,184)	—	—	—	16	(7,023)
Share-based payment	1,431	530	—	—	—	—	1,961
Disallowed interest carried forward	1,732	(408)	—	—	—	(193)	1,131
Others	628	1,223	—	(1,712)	—	(31)	108
	(452,110)	(133,553)	(2,197)	72,372	(195)	(1,724)	(517,407)
Tax losses carried forward	89,562	31,547	—	—	—	(2,231)	118,878
	(362,548)	(102,006)	(2,197)	72,372	(195)	(3,955)	(398,529)

As at December 31, 2019, the Corporation, its subsidiaries and joint ventures and associates have non-capital losses totaling approximately $440,000 that may be applied against future taxable income. The non-capital losses in Canada and the United-States expire gradually between 2026 and 2039. The non-capital losses in France are subject to restrictions over time but have no expiration date.

The Corporation recognized a deferred income tax asset on non-capital losses because it is probable that sufficient taxable profit and taxable capital gains will be available from hydroelectric, solar and wind projects currently in operation.

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

	As at January 1, 2018	Recognized in statement of earnings	Recognized in other comprehensive income	Recognized in business acquisitions	Recognized directly in equity	Net exchange differences	As at December 31, 2018
Deferred income tax assets (liabilities) in relation to:							
Property, plant and equipment	(159,943)	(10,034)	—	(35,624)	—	(961)	(206,562)
Intangible assets	(150,542)	(826)	—	(35,153)	—	2,527	(183,994)
Project development costs	11,403	8,127	—	(17,706)	—	103	1,927
Investments into subsidiaries and in joint ventures and associates	(4,455)	(26,454)	1,225	(103,562)	—	(2,618)	(135,864)
Non-repatriated income from foreign subsidiaries	(1,247)	220	—	—	—	—	(1,027)
Derivative financial instruments	52,721	1,987	9,420	4,794	—	161	69,083
Long-term loans and borrowings	(3,836)	2,138	—	3,827	—	117	2,246
Capitalized investment tax credits	—	63	—	1,309	—	—	1,372
Convertible debentures	(358)	196	—	—	(766)	—	(928)
Other liabilities	521	(841)	—	4,021	—	—	3,701
Financing fees	(4,186)	(1,710)	—	42	—	(1)	(5,855)
Share-based payment	1,381	50	—	—	—	—	1,431
Disallowed interest carried forward	—	1,732	—	—	—	—	1,732
Others	—	1,646	—	(965)	—	(53)	628
	(258,541)	(23,706)	10,645	(179,017)	(766)	(725)	(452,110)
Tax losses carried forward	53,698	4,982	645	29,019	—	1,218	89,562
	(204,843)	(18,724)	11,290	(149,998)	(766)	493	(362,548)

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

d. Unrecognized deductible temporary differences, unused tax losses and unused tax credits

	December 31, 2019	December 31, 2018
Tax losses - revenue in nature	133,899	292,350
Tax losses- capital in nature	3,508	5,920
Transaction costs	477	477
	137,884	298,747

The unrecognized tax losses-revenue in nature will expire gradually between 2020 and 2039.

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

12. EARNINGS PER SHARE

Basic	Year ended December 31 2019 Continuing operations	Year ended December 31 2019 Discontinued operations	Year ended December 31 2019 Total	Year ended December 31 2018 Continuing operations	Year ended December 31 2018 Discontinued operations	Year ended December 31 2018 Total
Net (loss) earnings attributable to owners	(47,723)	19,682	(28,041)	31,825	(685)	31,140
Dividends declared on preferred shares	(5,942)	—	(5,942)	(5,942)	—	(5,942)
Net (loss) earnings available to common shareholders	(53,665)	19,682	(33,983)	25,883	(685)	25,198
Weighted average number of common shares (in 000s)	134,658	134,658	134,658	130,030	130,030	130,030
Basic net (loss) earnings per share ($)	(0.40)	0.15	(0.25)	0.20	(0.01)	0.19

Diluted	Year ended December 31 2019 Continuing operations	Year ended December 31 2019 Discontinued operations	Year ended December 31 2019 Total	Year ended December 31 2018 Continuing operations	Year ended December 31 2018 Discontinued operations	Year ended December 31 2018 Total
Net (loss) earnings available to common shareholders (diluted)	(53,665)	19,682	(33,983)	25,883	(685)	25,198
Diluted Weighted average number of common shares (in 000s)	134,658	134,658	134,658	130,907	130,907	130,907
Diluted net earnings (loss) per share ($)	(0.40)	0.15	(0.25)	0.20	(0.01)	0.19

	Year ended December 31 2019	Year ended December 31 2018
Weighted average number of common shares (in 000s)	134,658	130,030
Effect of share options issue	—	674
Effect of shares held in trust related to the PSP plan	—	203
Diluted weighted average number of common shares (in 000s)	134,658	130,907
Shares that may be issued from the following equity instruments that are excluded from the potentially dilutive elements (in 000s):		
Effect of shares held in trust related to the PSP plan	301	203
Share options	170	—
Convertible debentures	13,777	14,167
	14,248	14,370

1. Share options for which the exercise price was below the average market price of common shares are included in the calculation of potentially dilutive equity instruments. Contingent share issuances have an anti-dilutive effect on loss per share.

13. RESTRICTED CASH AND SHORT-TERM INVESTMENTS

As at	December 31, 2019	December 31, 2018
Restricted cash accounts	3,569	10,397
Restricted proceeds account	28,654	13,948
Debt service payment accounts	7,228	5,636
	39,451	29,981

As required under several projects' credit agreements, the Corporation maintains restricted cash accounts and restricted proceeds accounts. The unused portion of the loans proceeds are held in restricted proceeds accounts managed by the lenders and amounts are transferred from time to time into the restricted cash accounts to finance the construction of the projects. The restricted cash accounts are used to pay the current construction costs of the projects and to hold the construction holdback amounts that will be released at the end of the construction of the respective projects. The Corporation also maintains debt service payment accounts.

14. ACCOUNTS RECEIVABLE

As at	December 31, 2019	December 31, 2018
Trade	61,539	94,437
Advances to related parties	20,756	964
Commodity taxes	1,417	2,241
Investment tax credits	711	671
Income taxes receivable	757	1,163
Other	7,085	4,410
	92,265	103,886

15. OTHER LONG-TERM ASSETS

As at	December 31, 2019	December 31, 2018
Hydrology/ wind power reserve	51,078	47,030
Major maintenance reserve	6,339	4,865
Security deposits	6,207	22,006
Other	8,381	—
	72,005	73,901

The availability of $56,482 ($51,024 in 2018) in the reserve accounts is restricted by credit agreements.

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

16. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facilities	Geothermal facilities	Facilities under construction	Other	Total
Cost								
As at January 1, 2019	3,095	2,089,405	2,025,711	155,130	418,317	336,345	17,518	5,045,521
Adoption of IFRS 16 (Note 2)	115,319	97	—	—	—	—	8,472	123,888
Adjusted balance as at January 1, 2019	118,414	2,089,502	2,025,711	155,130	418,317	336,345	25,990	5,169,409
Additions [1]	75	1,996	12,227	954	—	869,184	4,420	888,856
Investment tax credits	—	—	—	—	—	(179,071)	—	(179,071)
Transfer of assets upon commissioning	—	—	524,160	318,429	—	(845,087)	2,498	—
Business disposal (Note 5)	—	—	—	—	(418,317)	(62,739)	—	(481,056)
Dispositions	—	—	(1,503)	—	—	—	(169)	(1,672)
Other changes	7,024	19	15,566	38	—	(20)	(163)	22,464
Net foreign exchange differences	(4,704)	(483)	(61,727)	(8,473)	—	(15,660)	(114)	(91,161)
As at December 31, 2019	120,809	2,091,034	2,514,434	466,078	—	102,952	32,462	5,327,769
Accumulated depreciation								
As at January 1, 2019	—	(270,622)	(236,218)	(40,659)	(16,290)	—	(11,069)	(574,858)
Depreciation [2]	(4,732)	(39,542)	(97,087)	(10,157)	—	—	(3,489)	(155,007)
Business disposal (Note 5)	—	—	—	—	16,290	—	—	16,290
Dispositions	—	—	821	—	—	—	169	990
Net foreign exchange differences	60	164	4,480	223	—	—	(86)	4,841
As at December 31, 2019	(4,672)	(310,000)	(328,004)	(50,593)	—	—	(14,475)	(707,744)
Carrying amount as at December 31, 2019 [3]	116,137	1,781,034	2,186,430	415,485	—	102,952	17,987	4,620,025

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

1. The financing costs related to a specific project financing are entirely capitalized to the specific property, plant and equipment. Financing costs related to the revolving credit facilities are capitalized for the portion of the financing actually used for a specific property, plant and equipment. Additions in the current period include $20,139 ($8,995 in 2018) of capitalized financing costs incurred prior to commissioning.
2. An amount of $1,390 of the depreciation expense for the land leases is capitalized as a construction cost in facilities under construction.
3. Included in property, plant and equipment are right-of-use assets with a carrying amount of $120,171 ($112,989, $114 and $7,068 included in Lands, Hydroelectric facilities and Other, respectively) pursuant to lease agreements.

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

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facilities	Geothermal facilities	Facilities under construction	Other	Total
Cost								
As at January 1, 2018	3,055	2,081,857	1,410,294	124,322	—	—	14,476	3,634,004
Additions	69	7,887	611	386	13,394	161,349	1,964	185,660
Business acquisitions (Note 4)	—	—	575,995	28,168	430,305	165,862	1,052	1,201,382
Dispositions	(46)	(824)	(149)	(318)	(164)	—	(20)	(1,521)
Other changes	—	—	11,073	(3)	—	—	—	11,070
Net foreign exchange differences	17	485	27,887	2,575	(25,218)	9,134	46	14,926
As at December 31, 2018	3,095	2,089,405	2,025,711	155,130	418,317	336,345	17,518	5,045,521
Accumulated depreciation								
As at January 1, 2018	—	(230,616)	(172,439)	(33,733)	—	—	(8,978)	(445,766)
Depreciation	—	(40,019)	(62,217)	(6,849)	(16,580)	—	(1,986)	(127,651)
Dispositions	—	280	4	4	24	—	20	332
Net foreign exchange differences	—	(267)	(1,566)	(81)	266	—	(125)	(1,773)
As at December 31, 2018	—	(270,622)	(236,218)	(40,659)	(16,290)	—	(11,069)	(574,858)
Carrying amount as at December 31, 2018	3,095	1,818,783	1,789,493	114,471	402,027	336,345	6,449	4,470,663

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

17. INTANGIBLE ASSETS

	Hydroelectric facilities	Wind farm facilities	Solar facilities	Geothermal facilities	Facilities under construction	Total
Cost						
As at January 1, 2019	559,853	377,716	10,776	200,802	26,389	1,175,536
Transfer of assets upon commissioning	—	26,389	—	—	(26,389)	—
Business disposal (Note 5)	—	—	—	(200,802)	—	(200,802)
Disposal	—	(7)	—	—	—	(7)
Other changes	8,468	—	—	—	—	8,468
Net foreign exchange	(128)	(15,338)	27	—	—	(15,439)
As at December 31, 2019	568,193	388,760	10,803	—	—	967,756
Accumulated amortization						
As at January 1, 2019	(170,470)	(73,606)	(3,213)	(3,238)	—	(250,527)
Amortization	(15,281)	(25,148)	(533)	—	—	(40,962)
Business disposal (Note 5)	—	—	—	3,238	—	3,238
Disposal	—	7	—	—	—	7
Net foreign exchange	73	2,640	2	—	—	2,715
As at December 31, 2019	(185,678)	(96,107)	(3,744)	—	—	(285,529)
Net value as at December 31, 2019	382,515	292,653	7,059	—	—	682,227

	Hydroelectric facilities	Wind farm facilities	Solar facility	Geothermal facilities	Facilities under construction	Total
Cost						
As at January 1, 2018	562,756	287,861	9,538	—	—	860,155
Additions	—	—	—	2,597	—	2,597
Business acquisitions (Note 4) [1]	—	81,517	1,220	211,679	26,389	320,805
Disposal	(73)	—	—	—	—	(73)
Other changes	(3,046)	—	—	—	—	(3,046)
Net foreign exchange	216	8,338	18	(13,474)	—	(4,902)
As at December 31, 2018	559,853	377,716	10,776	200,802	26,389	1,175,536
Accumulated amortization						
As at January 1, 2018	(152,289)	(51,102)	(2,683)	—	—	(206,074)
Amortization	(18,138)	(21,504)	(531)	(3,303)	—	(43,476)
Other changes	73	—	—	—	—	73
Net foreign exchange	(116)	(1,000)	1	65	—	(1,050)
As at December 31, 2018	(170,470)	(73,606)	(3,213)	(3,238)	—	(250,527)
Net value as at December 31, 2018	389,383	304,110	7,563	197,564	26,389	925,009

1. Includes intangibles acquired through business acquisitions made in 2017 which were subject to purchase price allocation adjustments in 2018. The intangibles resulting from these purchase price allocation adjustments are not included in Note 4.

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

18. PROJECT DEVELOPMENT COSTS

As at	December 31, 2019	December 31, 2018
Cost		
Beginning of year	30,119	—
Project development cost acquired on business acquisitions (Note 4)	—	19,298
Business disposal (Note 5)	(17,822)	—
Additions	7,792	10,048
Impairment of project development costs	(8,184)	—
Net foreign exchange	(770)	773
End of year	11,135	30,119

An impairment charge of $8,184 was recognized on a project for which uncertainties exist regarding the timing and profitability of any development. For the year ended December 31, 2018, no impairment charge was recognized.

19. GOODWILL

Allocation of goodwill to each significant CGU or group of CGUs is as follows:

As at	Hydroelectric facilities	Wind farm facilities	Solar facilities	HS Orka hf	Facilities under construction	Total
As at January 1, 2019	20,036	42,438	93	47,266	162	109,995
Business disposal (Note 5)	—	—	—	(47,266)	—	(47,266)
Net foreign exchange	(2,063)	—	—	—	—	(2,063)
As at December 31, 2019	17,973	42,438	93	—	162	60,666

As at	Hydroelectric facilities	Wind farm facilities	Solar facilities	HS Orka hf	Facilities under construction	Total
As at January 1, 2018	8,269	30,311	—	—	—	38,580
Business acquisitions (Note 4) [1]	11,767	11,004	93	47,266	162	70,292
Net foreign exchange	—	1,123	—	—	—	1,123
As at December 31, 2018	20,036	42,438	93	47,266	162	109,995

1. Includes goodwill acquired through business acquisitions made in 2017 which were subject to purchase price allocation adjustments in 2018. The goodwill resulting from these purchase price allocation adjustments are not included in Note 4.

On December 31, 2019, the Corporation conducted its annual goodwill impairment tests. Based on the result of these tests, no impairment charge was required.

The recoverable amount of each CGU was 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 discount rates of 3.89% to 5.96% (4.7% to 5.2% in 2018).

Assumptions used to determine the recoverable amount of assets are the following:

- The discount rate considers the weighted average between the consolidated cost of debt and the consolidated cost of equity, adjusted with alpha factors specific to each operating segment and country in which the facility operates.
- The expected selling price of electricity once the power purchase agreements are renewed or on the spot market.
- A cash-generating unit is an individual 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 expected production. These long-term averages are expected to approximate actual results.

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

20. ACCOUNTS PAYABLE AND OTHER PAYABLES

As at	December 31, 2019	December 31, 2018
Trade and other payables	90,809	104,837
Current portion of construction holdbacks	31,311	3,440
Dividends payable to shareholders	25,882	24,093
Interest payable	20,200	18,423
Income taxes payable	4,005	8,836
Commodity taxes	3,394	4,310
Salaries and benefits	556	921
	176,157	164,860

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

21. LONG-TERM LOANS AND BORROWINGS

(references to US$ are in thousands)	Currency	Interest rates	Maturity	December 31, 2019	December 31, 2018
Corporate indebtedness					
Revolving term credit facility	CAD	3.82%-3.97%	2023	490,996	387,409
Subordinated unsecured term loan	CAD	5.13%	2023	150,000	150,000
Unsecured short-term credit facility term loan	CAD	—	2019	—	228,000
				640,996	765,409
Convertible debentures					
4.65% Convertible Debentures	CAD	4.65%	2026	136,435	—
4.75% Convertible Debentures	CAD	4.75%	2025	142,392	140,996
4.25% Convertible Debentures	CAD	4.25%	2020	—	97,652
				278,827	238,648
Tax equity financing					
Wind segment					
Foard City	USD	7.50%[1]	2029[2]	285,433	—
Solar Segment					
Phoebe	USD	7.14%[1]	2026[2]	53,185	—
Others	USD	8.00%	2022-2023	1,332	2,289
				339,950	2,289
Project loans					
Hydroelectric segment					
Rutherford Creek	CAD	6.88%	2024	23,670	28,009
Ashlu Creek	CAD	3.72%	2025	83,631	86,606
Sainte-Marguerite	CAD	7.40%-8.00%	2025-2064	61,192	63,888
Magpie	CAD	4.34%-4.37%	2025-2031	46,321	49,238
Fitzsimmons Creek	CAD	2.81%	2026	19,312	19,786
Big Silver Creek	CAD	4.57%-4.76%	2041-2056	196,420	197,223
Harrison Operating Facilities	CAD	3.91%-6.58%	2049	447,509	451,021
Kwoiek Creek	CAD	5.08%-10.07%	2052-2054	167,257	169,043
Northwest Stave River	CAD	5.30%	2053	71,972	71,972
Tretheway Creek	CAD	4.99%	2055	92,916	92,916
Boulder Creek and Upper Lillooet	CAD	4.22%-4.46%	2043-2056	491,643	491,643
Others	CAD	—	2019	—	12
Wind segment					
Plan Fleury	EURO	1.00%-1.65%	2019-2034	48,740	56,383
Les Renardières	EURO	1.05%-1.70%	2019-2034	43,050	49,878
Rougemont 1	EURO	0.56%	2019-2035	70,179	80,596
Rougemont 2	EURO	0.60%	2019-2035	80,096	91,425
Montjean	EURO	2.56%-2.95%	2026-2031	21,804	25,367
Theil Rabier	EURO	2.56%-2.94%	2026-2031	21,804	25,367
Beaumont	EURO	2.16%-2.63%	2027-2031	28,922	33,464
Yonne	EURO	1.30%	2028-2031	94,762	83,447
Vaite	EURO	0.76%	2035	72,849	83,772
Innergex Cartier Energie	CAD	3.58%	2032	531,889	570,408
Mesgi'g Ugju's'n	CAD	3.70%-4.28%	2026-2036	244,331	250,923
Innergex Europe	CAD	8.00%	2046	77,957	77,957
Foard City	USD	1.75%-1.88%	2026	29,072	—
Other	EURO	1.86%-5.73%	2025-2030	71,247	84,262

(continued)	Currency	Interest rates	Maturity	December 31, 2019	December 31, 2018
Solar segment					
Stardale	CAD	3.45%	2032	79,454	87,575
Phoebe	USD	3.26%	2019-2026	144,931	204,257
Others	USD	5.35%-5.81%	2023-2026	17,840	19,603
Other					
Alterra (including US$21,109 (US$20,775 in 2018))	CAD	7.65%-7.83%	2023	117,167	118,548
HS Orka	EURO	N/A	—	—	96,515
				3,497,937	3,761,104
Total long-term loans and borrowings				4,757,710	4,767,450
Deferred financing costs				(66,041)	(59,053)
				4,691,669	4,708,397
Current portion of long-term loans and borrowings				(410,083)	(445,928)
Long-term loans and borrowings				4,281,586	4,262,469

1. The interest rates reflect the internal rate of return required by the respective tax equity investors.
2. The maturity date of these obligations are subject to change and are driven by the dates on which the tax equity investor reaches the agreed upon target rate of return.

The carrying amount of assets pledged to secure the loans totalled $4,692,241 as at December 31, 2019 ($5,859,950 in 2018).

Letters of credits under revolving term credit facility and project loans amount to $161,850 ($243,602 in 2018).

a. Corporate Indebtedness

Revolving Term Credit Facility

The Corporation has access to a revolving term credit facility maturing in 2023. The available facility amount is $700,000 with an option, subject to the lender's consent, to increase to a total amount of up to $900,000. The facility has covenants requiring a minimum interest coverage and a maximum debt coverage ratios. The applicable interest rate on this revolving credit facility is variable, based on the bank's prime rate, bankers' acceptance rates, US Base Rate, LIBOR or EURIBOR plus a spread which depends on leverage ratio. As of December 31, 2019, an amount of $47,082 has been used to issue letters of credit.

Moreover, the Corporation has access to a letter of credit facility of an amount of up to $90,000 guaranteed by Export Development Canada. As of December 31, 2019, letters of credit have been issued for an amount of $54,344.

Subordinated Unsecured Term Loan

The Corporation has a subordinated unsecured term loan maturing in 2023 and repayable in full at maturity.

Unsecured Short-term Credit Facility Term Loan

The Corporation has repaid the unsecured short-term credit facility term loan with the net proceeds from the sale of its equity interest in HS Orka. The facility was subsequently cancelled following its full repayment.

b. Convertible debentures

Redemption of the 4.25% Convertible Debentures

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

On September 5, 2019, the Corporation issued a notice of redemption and expiry of conversion privilege regarding the 4.25% Convertible Debentures, for the aggregate principal amount of $100,000. Of that principal amount, $86,652 was converted at the holders' request into 5,776,795 common shares of the Corporation at a conversion price of $15 per share. The remaining principal amount of $13,348 was redeemed at par on October 8, 2019, at a price of one thousand dollars per convertible debenture, plus accrued and unpaid interest up to, but excluding, October 8, 2019. The redemption was financed with drawings under the Corporation's revolving term credit facility. On October 8, 2019, the 4.25% Convertible Debentures were delisted from the TSX.

Issuance of 4.65% Convertible Debentures

On September 30, 2019, the Corporation issued an aggregate principal amount of $125,000 of 4.65% Convertible Debentures at a price of a thousand dollars per convertible debenture, bearing interest at a rate of 4.65% per annum, payable semi-annually on October 31 and April 30 each year, commencing on April 30, 2020. The convertible debentures are convertible at the holder's option into common shares of the Corporation at a conversion price of $22.90 per share, representing a conversion rate of 43.6681 common shares per each thousand-dollar of principal amount of convertible debentures. The convertible debentures mature on October 31, 2026. On or after October 31, 2022, and before October 31, 2024, Innergex may redeem the debentures at par, plus accrued and unpaid interest, in certain circumstances. On or after October 31, 2024, Innergex may redeem the debentures at par, plus accrued and unpaid interest. On October 2, 2019, the Corporation issued an additional $18,750 aggregate principal amount of 4.65% Convertible Debentures following the exercise, in full, of the over-allotment option by the underwriters.

Proceeds from issue of 4.65% convertible debentures	143,750
Transaction costs	(6,536)
Net proceeds	137,214
Amount classified as equity ($770 net of $279 of deferred income taxes)	(1,049)
Liability component of the convertible debentures at the time of issuance	136,165

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.

c. Tax Equity Financing and Project Loans

Tax equity investors in U.S. solar and wind projects generally require sponsor guarantees as a condition to their investment. To support the tax equity investment in Phoebe and Foard City, Alterra Power Corp., a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters which are substantially under its control, and are very unlikely to occur.

Financing of the Foard City Wind Project and Term Conversion

On May 8, 2019, the Corporation entered into a construction and long-term credit agreement for the Foard City wind project.

Project loan

The credit agreement comprises two facilities:

- A US$23,370 construction loan facility carrying an interest rate of LIBOR + 1.00%. On September 27, 2019, the construction loan was converted into a term loan carrying an interest rate of LIBOR +1.75% for the first 4 years following term conversion, and +1.88% thereafter until maturity. All of the variable interest rate exposure has been hedged through an interest rate swap which became effective on September 30, 2019, resulting in a fixed interest rate of 2.25%. The term loan is for a period of 7 years with principal payments due upon maturity. As at December 31, 2019, an aggregate principal amount of US$22,383 ($29,072) was outstanding.
- A US$267,540 tax equity bridge loan carrying an interest rate of LIBOR +1.00%. On September 27, 2019, the tax equity bridge loan, which principal amount then aggregated to US$236,444 ($312,200), was reimbursed with the proceeds from the tax equity investor's contribution following the completion of commissioning activities.

Tax equity financing

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

The amount of the tax equity financing represents the proceeds received from the tax equity investor in exchange for Class A shares in the subsidiary, aggregating to US$282,280 ($372,723), net of the allocation of U.S. renewable tax incentives (PTCs), taxable income and cash distributions paid to date. The Foard City wind project is eligible to receive PTCs related to its wind power generation for the first ten years of the project's operations (until 2029). The Corporation anticipates the Flip Point date of the Foard City tax equity financing to occur in 2029, coinciding with the period that the project will benefit from the PTCs.

The tax equity investors' taxable income (losses), PTCs and cash distributions allocations are detailed in the table below. After the Flip Point, the Foard City tax equity investors will retain a 5% financial interest in the project which will be accounted for as non-controlling interests.

	Tax Equity Investors
Taxable income (losses) and PTCs	99.0%
Cash distributions	5.0%
Pay-go contributions	Various [1]

1. Prior to the Flip Point, pay-go contributions will be made by the tax equity investor at a rate of $25,00 per MWh for annual production in excess of 1,165 GWh, up to a maximum of US$4,900 per year and an all-time maximum of US$36,485.

Financing of the Phoebe Solar Project and Term Conversion

On July 2, 2018, Innergex acquired Phoebe Energy Project, LLC and concurrently closed a construction and long-term project financing.

Project loan

The financing agreement comprises two facilities or tranches:

- A US$115,864 construction loan carrying an interest rate of 1-month LIBOR +1.5%. On November 19, 2019, the construction loan, which principal amount then aggregated to US$115,864 ($152,940) was converted into a term loan carrying an interest rate of 3-month LIBOR +2.0% for the first four years and LIBOR +2.25% thereafter (approximately 90% fixed through an interest rate swap entered into on July 3, 2018 resulting in a fixed interest rate of 5.07% for the first four years and 5.32% thereafter); The term loan is for a period of 7 years with principal payments beginning in 2020 and the remaining 85% of the principal will be due upon maturity on September 30, 2026. As at December 31, 2019, an aggregate principal amount of US$111,589 ($144,931) was outstanding.
- A US$176,225 tax equity bridge loan carrying an interest rate of 1-month LIBOR +1.5%. On November 19, 2019, the tax equity bridge loan, which principal amount then aggregated to US$176,225 ($232,617), was reimbursed with the proceeds from the tax equity investor's contribution following the completion of commissioning activities.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $4,819.

Tax equity financing

The amount of the tax equity financing represents the proceeds received from the tax equity investor in exchange for Class A shares in the subsidiary, aggregating to US$184,564 ($244,281), net of the allocation of the U.S. renewable tax incentives (ITCs), taxable income and cash distributions paid to date. During 2019, the construction of the Phoebe solar project has generated ITCs, which were recognized as a reduction in the cost of the Phoebe property plant and equipment and allocated to the tax equity investor as a reimbursement of the amount owed. The Corporation anticipates the Flip Point date of the Phoebe tax equity financing to occur in 2026.

The tax equity investors' taxable income (losses), ITCs and cash distributions allocations are detailed in the table below. After the Flip Point, the Phoebe tax equity investors will retain a 5% financial interest in the project which will be accounted for as non-controlling interests.

	Tax Equity Investors
Taxable income (losses) and ITCs	99.0% [1]
Cash distributions	Various [2]

1. Allocation of taxable income (loss) and ITCs will be 99% to the tax equity investor until February 15, 2020, then will be 66.67% from February 15, 2020, to December 31, 2024, and return to 99.0% until the Flip Point.
2. Phoebe's cash distribution amounts to the tax equity investor are fixed and defined within the partnership agreement. All amounts of distributable cash above these fixed and defined distributions are distributed at the rate of 10.62% and 89.38% to the tax equity investor and the Corporation, respectively.

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

Yonne Project Loan Refinancing

On October 16, 2019, Innergex refinanced the Yonne project loan facilities. The initial loan facilities were comprised of the following tranches:

- A €14,864 loan bearing a variable interest rate at EURIBOR +1.90%, repayable in quarterly installments and maturing in 2028. The balance on this loan was of €7,226 ($10,433) as at October 16, 2019.
- A €44,600 loan bearing a variable interest rate at EURIBOR +1.95%, repayable in quarterly installments and maturing in 2031. The balance on this loan was of €42,028 ($60,680) as at October 16, 2019.

Those loan facilities were refinanced into two new tranches:

- A €33,800 ($48,800) loan bearing a fixed interest rate at 1.30%, repayable in quarterly installments and maturing in 2035.
- A €32,585 ($47,046) loan bearing a fixed interest rate at 1.30%, repayable in quarterly installments and maturing in 2031.

Stardale Refinancing

On December 20, 2019, Innergex amended the Stardale project long-term loan to extend the maturity period by two years from 2030 to 2032. The loan bears interest at the BA rate plus an applicable credit margin. The principal repayments are variable and are set at $2,989 for 2020.

The refinancing was accounted for as a debt modification under IFRS 9. The loan was remeasured at the original effective interest rate, resulting in a gain represented by the difference between the original contractual cash flows and the modified cash flows discounted at the original effective interest rate. The gain of $2,883 was recognized in the consolidated statement of earnings under Other net (revenues) expenses.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $7,869.

22. OTHER LIABILITIES

	Contingent considerations	Asset retirement obligations	Interests payable on SM S.E.C. debenture	Future ownership rights	Pension fund obligations	Below market contracts	Lease liabilities	Total
As at January 1, 2019	1,762	88,659	18,002	21,883	26,926	16,618	—	173,850
Adoption of IFRS 16 (Note 2)	—	—	—	—	—	—	122,270	122,270
Business disposal (Note 5)	—	—	—	—	(26,926)	(16,618)	—	(43,544)
New obligations	—	16,528	—	—	—	—	—	16,528
Interest expense included in finance cost	—	—	4,064	—	—	—	—	4,064
Accretion expense included in finance cost	54	3,392	—	1,049	—	—	—	4,495
Remeasurement	—	15,582	—	8,468	—	—	6,882	30,932
Payment of lease liabilities	—	—	—	—	—	—	(4,756)	(4,756)
Impact of foreign exchange fluctuations	—	(2,790)	—	—	—	—	(4,608)	(7,398)
As at December 31, 2019	1,816	121,371	22,066	31,400	—	—	119,788	296,441
Current portion of other liabilities	(761)	—	—	—	—	—	(3,259)	(4,020)
Long-term portion of other liabilities	1,055	121,371	22,066	31,400	—	—	116,529	292,421

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

	Contingent considerations	Asset retirement obligations	Interests payable on SM S.E.C. debenture	Future ownership rights	Pension fund obligations	Below market contracts	Total
As at January 1, 2018	1,950	40,678	13,458	23,921	—	—	80,007
Liability assumed as part of the business acquisition (Note 4)	—	33,617	—	—	27,841	20,131	81,589
Interest expense included in finance cost	—	—	4,544	—	—	—	4,544
Accretion expense included in finance cost	63	2,194	—	1,008	—	—	3,265
Remeasurement	—	11,070	—	(3,046)	—	—	8,024
Changes in pension fund obligations	—	—	—	—	539	—	539
Amortization of below market contract	—	—	—	—	—	(2,381)	(2,381)
Payment of contingent considerations	(251)	—	—	—	—	—	(251)
Impact of foreign exchange fluctuations	—	1,100	—	—	(1,454)	(1,132)	(1,486)
As at December 31, 2018	1,762	88,659	18,002	21,883	26,926	16,618	173,850
Current portion of other liabilities	(505)	—	—	—	—	—	(505)
Long-term portion of other liabilities	1,257	88,659	18,002	21,883	26,926	16,618	173,345

a. Contingent considerations

An acquisition realized in 2011 provides for the potential payment of additional amounts to the vendors over a period commencing on the acquisition date and ending in 2056. The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. The maximum aggregate amount of all deferred payments under this acquisition is limited to a present value amount of $35,000 as at the acquisition date.

In connection with the Magpie Acquisition in 2017, the Corporation assumed an obligation to pay contingent consideration to the Minganie Regional County Municipality until the convertible debenture issued by Magpie L.P. is converted. Upon conversion, the Minganie Regional County Municipality will be entitled to a participation of 30% in Magpie L.P.

b. Asset retirement obligations

Asset retirement obligations primarily arise from obligations to retire wind farms and the solar facilities upon expiry of the site leases. The wind farms and solar facilities were constructed on sites held under leases expiring at least 25 years after the signing date.

The cash flows were discounted at rates between 1.24% and 4.35% as at December 31, 2019 (2.31% to 4.70% in 2018) to determine the obligations.

c. Interest payable on SM S.E.C. debenture

In 2014, a debenture was issued by Innergex Sainte-Marguerite L.P. to Régime de Rentes du Mouvement Desjardins ("RRMD") for a total amount of $42,401. This debenture carries an interest rate of 8.00%; it has no predetermined repayment schedule and matures in 2064. The partner, RRMD, is considered a related party. Unpaid interests are compounded and are recorded in other long-term liabilities.

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

d. Future ownership rights

Other liabilities includes various liabilities related to future ownership rights owned by First Nations for the Upper Lillooet River, Boulder Creek, Big Silver Creek and Tretheway Creek facilities, the counterpart of which is capitalized into the intangible assets.

e. Pension fund obligations and below market contracts

During the year ended December 31, 2019, the Corporation disposed of its ownership interests in the subsidiary HS Orka which included their pension fund and below market contracts obligations.

f. Lease liabilities

The Corporation enters into various leases for the conduct of its operations. The main portion of the leases relate to the right of use of land, mainly for the Corporation's installed wind turbines and solar panels. The land leases run for various number of years, with subsequent options to renew, which the Corporation expects to exercise up to its projects' respective expected useful lives. The majority of leases provide for additional rent payments that are based on changes in local price indices.

23. 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"), up to 3,400,000 Cumulative Floating Rate Preferred Shares, Series B (the "Series B Preferred Shares") and up to 2,000,000 Cumulative Redeemable Fixed Rate Preferred Shares, Series C (the "Series C Preferred Shares").

a) Common shares

The change in the number of common shares was as follows:

As at	December 31, 2019	December 31, 2018
Issued and fully paid		
Beginning of the year	132,986,850	108,608,083
Issued following the Alterra acquisition (Note 4 b)	—	24,327,225
Issued through dividend reinvestment plan	169,450	748,754
Exercise of share options	472,737	—
Conversion of debentures (Note 21)	5,776,795	—
Buybacks	—	(697,212)
End of year	139,405,832	132,986,850
Held in trust under the PSP plan		
Beginning of the year	(203,416)	(273,762)
Purchased	(170,000)	—
Distributed	72,692	70,346
End of year	(300,724)	(203,416)
Common shares outstanding at end of the year	139,105,108	132,783,434

Buyback of common shares

On May 21, 2019, Innergex announced that it has received approval from the Toronto Stock Exchange (TSX) to proceed with a normal course issuer bid on its common shares (the New Bid). Under the New Bid, the Corporation could purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.5% of the 133,559,963 issued and outstanding common shares of the Corporation as at May 15, 2019. The Bid commenced on May 24, 2019 and will terminate on May 23, 2020. No common shares have been purchased and cancelled in 2019 (697,212 in 2018).

b) Contributed surplus from reduction of capital account on common shares

A special resolution 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 was adopted on May 15, 2018. This resulted in a decrease of the shareholders' capital account of $337,785 and an equivalent increase of the contributed surplus from reduction of capital on common shares account.

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. 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. For the initial five-year period to, but excluding January 15, 2016 (the “Initial Fixed Rate Period”), the dividends were payable at an annual rate equal to $1.25 per share. The annual dividend rate for the five-year period starting January 15, 2016, equals $0.902 per share.

(in thousands of Canadian dollars, except as noted and amounts 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 five-year term to maturity 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 Series A Preferred Shares were not redeemable by the Corporation prior to January 15, 2016. None were redeemed at that date. The next redemption date is January 15, 2021, and on January 15 every five years thereafter, at which time, the Corporation may, at its option, redeem all or any number of the outstanding Series A Preferred Shares.

Series B Preferred Shares

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 Bill 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.

Series C Preferred Shares

On December 11, 2012, the Corporation issued a total of 2,000,000 Series C Preferred Shares at $25.00 per share for aggregate gross proceeds of $50,000. Holders of the Series C Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends as and when declared by the Corporation's Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.4375 per share. The Series C Preferred Shares were not redeemable by the Corporation prior to January 15, 2018. The Series C Preferred Shares do not have a fixed maturity date and are not redeemable at the option of the holders.

d) Equity-based compensation

Share option plan

The Corporation has a share 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 share option plan will have an exercise price of not less than the market price of the common shares at the date of grant of the option, calculated as the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

The maximum number of common shares of the Corporation available for issuance pursuant to options granted under the share option plan is 4,064,123. Any common shares subject to an option that expires or terminates without having been fully exercised may be subject to a further option. The number of common shares issuable to non-executive directors of the Corporation under the share 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 share option plan vest in equal amounts on a yearly basis over a period of four to five years following the grant date.

During 2019, 2,122,764 share options were exercised resulting in 472,737 common shares issued. The difference between the 2,122,764 options exercised and the 472,737 common shares issued is the result of the exercise of the options without disbursement by the holders and the withholding of deductions at source by the Corporation, as authorized by the share option plan and the Board of Directors.

Also 78,142 share options were granted during 2019. The options granted under the share options plan vest in equal amounts on a yearly basis over a period of four years following the grant date. Options must be exercised before August 27, 2026 at an exercise price of $14.41.

The following table summarizes outstanding share options of the Corporation as at December 31, 2019 and 2018:

	December 31, 2019		December 31, 2018	
	Number of options (000's)	Weighted average exercise price ($)	Number of options (000's)	Weighted average exercise price ($)
Outstanding - beginning of year	2,782	10.14	2,782	10.14
Granted during the year	78	14.41	—	—
Exercised during the year	(2,122)	9.85	—	—
Outstanding - end of year	738	11.52	2,782	10.14
Options exercisable - end of year	589	10.78	2,661	9.94

The following options were outstanding and exercisable as at December 31, 2019:

Year of granting	Number of options outstanding (000's)	Exercise price ($)	Number of options exercisable (000's)	Year of maturity
2010	158	8.75	158	2020
2013	134	9.13	134	2020
2014	165	10.96	165	2021
2016	126	14.65	94	2023
2017	77	14.52	38	2024
2019	78	14.41	—	2026
	738		589	

Fair value is determined at the date of the grant and each tranche is recognized on a graded-vesting basis over the period during which the options vest and is measured using the Black-Scholes pricing model taking into account the terms and conditions upon which the options were granted.

The following assumptions were used to estimate the fair value of the options issued to grantees during the year:

	December 31, 2019
Risk-free interest rate	1.57%
Expected annual dividend per common share	$ 0.70
Expected life of options	6
Expected volatility	20.25%

The weighted average contractual life of the outstanding share options is five years. Expected volatility is estimated by considering historic average share price volatility.

Performance Share Plan (the "PSP Plan")

The goal of the PSP Plan is to motivate the executive officers to create long-term economic value for the Corporation and its shareholders. This portion of the Equity-Based Incentive Plan focuses executive officers on delivering business performance over the next three years against the total shareholder value and relative to a peers group. The award is paid out at the end of the three years, depending on how well the Corporation performed against targets set at the beginning of the three-year period.

The vesting date of the performance share rights is determined on the grant date which shall not exceed three (3) years thereafter. The payouts are made in shares, so the value fluctuates based on share price performance from the beginning of the grant. On the vesting date, each performance share right entitles its holder to one Common Share of the Corporation with all the reinvested dividends accrued thereon from the grant date, such dividend being either paid in cash, in shares or in a combination of both at the sole discretion of the Corporation.

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

The Corporation's Deferred Share Unit Plan (the "DSU Plan")

Under the Corporation's DSU Plan, directors and officers may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation. A DSU is a unit that has a value based upon the value of one Common Share. When a dividend is paid on Common Shares, the director's DSU account is credited with additional DSUs equivalent to the dividend paid.

DSUs cannot be redeemed for cash until the director leaves the Board or the officer leaves. DSUs are not shares, cannot be converted to shares, and do not carry voting rights. DSUs received by directors and officers in lieu of cash compensation and held by them represent an at-risk investment in the Corporation. The value of DSUs is based on the value of the Common Shares, and therefore is not guaranteed.

The number of PSP and DSU has varied as follows, for the years ended:

	December 31, 2019		December 31, 2018	
(in 000s)	PSP	DSU	PSP	DSU
Balance beginning of year	264	56	368	28
Granted during the year	343	22	—	26
Paid out during the year	(175)	—	(118)	—
Dividend reinvestment during the year	17	3	14	2
Balance end of year	449	81	264	56

From time to time, the Corporation provides instructions to a trustee under the terms of a Trust Agreement to purchase common shares of the Corporation in the open market in connection with the PSP plan. These shares are held in Trust for the benefit of the beneficiaries until the PSPs become vested or cancelled. The cost of these purchases has been deducted from share capital.

A compensation expense of $4,613 was recorded during the year ended December 31, 2019 with respect to the PSP and DSU plan ($2,089 in 2018).

e) Dividend Reinvestment Plan ("DRIP")

The Corporation implemented a 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, without paying fees such as brokerage commissions and service charges. Shares will either be purchased on the open market or issued from treasury. During the year ended December 31, 2019, 169,450 shares (748,754 shares in 2018) were issued from treasury under the DRIP.

f) Dividend Declared on common shares

The following dividends were declared on common shares by the Corporation:

	Year ended December 31	
	2019	2018
Dividends declared on common shares ($/share)	0.70	0.68

Dividend Declared on common shares not recognized at the end of the reporting period

The following dividends will be paid by the Corporation on April 15, 2020:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
02/27/2020	3/31/2020	4/15/2020	0.1750	0.2255	0.359375

24. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

	Foreign currency translation differences for foreign operations	Foreign exchange (loss) gain on the designated hedges on the net investments in foreign operations	Cash flow hedge - interest rate and power price risks	Share of cash flow hedge of joint ventures and associates - interest rate and power price risks	Defined benefit plan actuarial losses	Total
Balance as at January 1, 2019	6,947	(6,341)	(25,887)	(8,795)	(416)	(34,492)
Business disposal (Note 5)	17,061	—	(61)	6,112	416	23,528
Exchange differences on translation of foreign operations	(31,713)	—	—	—	—	(31,713)
Hedging gain (loss) of the reporting period	—	4,021	23,688	(1,872)	—	25,837
Share of non-controlling interest	449	(469)	3,826	—	—	3,806
Related deferred tax	—	(540)	(3,145)	1,488	—	(2,197)
Balance as at December 31, 2019	(7,256)	(3,329)	(1,579)	(3,067)	—	(15,231)

	Foreign currency translation differences for foreign operations	Foreign exchange (loss) gain on the designated hedges on the net investments in foreign operations	Cash flow hedge - interest rate and power price risks	Share of cash flow hedge of joint ventures and associates - interest rate and power price risks	Defined benefit plan actuarial losses	Total
Balance as at January 1, 2018	1,061	(1,074)	9,279	663	—	9,929
Discontinued operations	(17,061)	—	61	(6,112)	(416)	(23,528)
Exchange differences on translation of foreign operations	22,786	—	—	—	—	22,786
Hedging loss of the reporting period	—	(6,199)	(49,404)	(59)	—	(55,662)
Share of non-controlling interest	(44)	287	450	—	—	693
Related deferred tax	205	645	13,727	(3,287)	—	11,290
Balance as at December 31, 2018	6,947	(6,341)	(25,887)	(8,795)	(416)	(34,492)

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

25. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Year ended December 31	
	2019	2018
Accounts receivable	(5,315)	9,261
Prepaid and others	(1,509)	2,161
Accounts payable and other payables	29,226	(20,070)
	22,402	(8,648)

b. Additional information

	Year ended December 31	
	2019	2018
Finance costs paid relative to operating activities before interest on leases	(194,726)	(170,960)
Interest on leases paid relative to operating activities	(1,189)	—
Capitalized interest relative to investing activities	(16,438)	(5,031)
Capitalized interest on leases relative to investing activities	(1,949)	—
Total finance costs paid	(214,302)	(175,991)
Non-cash transactions:		
Unpaid property, plant and equipment	21,456	5,099
Unpaid long term assets	(2,000)	—
Unpaid intangible assets	—	(169)
Unpaid project development costs	(919)	919
Common shares issued through the conversion of convertible debentures	86,652	—
Common shares issued through share options exercised	1,323	—
Shares vested in PSP plan	1,057	948
Remeasurement of asset retirement obligations	15,582	11,070
New asset retirement obligations	16,528	—
Remeasurement of lease liabilities	6,882	—
Remeasurement of future ownership rights	8,468	(3,046)
Common shares issued through dividend reinvestment plan	2,402	9,929
Common shares issued upon the acquisition of Alterra	—	330,607
Unpaid investment in joint venture and associates	(13,753)	13,154
Investment from non-controlling interests in subsidiaries	—	(507)
Investment tax credits	179,071	—

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

c. Changes in liabilities arising from financing activities

	Year ended December 31	
	2019	2018
Changes in long-term debt		
Long-term debt at beginning of year	4,469,749	3,153,262
Reclassified as held for sale	(96,515)	—
Increase of long-term debt	1,707,358	2,053,185
Repayment of long-term debt	(1,323,827)	(1,111,079)
Payment of deferred financing costs	(20,386)	(26,736)
Business acquisitions (Note 4)	—	333,800
Investment tax credits	(179,071)	—
Tax attributes	(88,402)	(764)
Production tax credits	(11,238)	—
Other non-cash finance costs	21,860	17,866
Net foreign exchange differences	(66,686)	50,215
Long-term debt at end of year	4,412,842	4,469,749
Changes in convertible debentures		
Convertible debentures at beginning of year	238,648	96,246
Issuance of convertible debentures issued	143,750	150,000
Transaction costs	(6,536)	(6,910)
Redemption of convertible debentures	(13,348)	—
Convertible debentures converted into common shares	(86,652)	—
Amount classified as equity	(709)	(2,865)
Accretion of convertible debentures	3,674	2,177
Convertible debentures at end of year	278,827	238,648

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

26. SUBSIDIARIES

Details of non-wholly-owned subsidiaries that have non-controlling interests

Name of subsidiaries	Place of creation and operation	Proportion of ownership interests and voting rights held by non-controlling interests		Earnings (loss) allocated to non-controlling interests for the year ended		Non-controlling interests (deficit)	
		Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018
Harrison Hydro L.P. and its subsidiaries	Canada	49.99%	49.99%	(6,041)	(1,607)	45,235	51,276
Creek Power Inc. and its subsidiaries	Canada	—%	—%	—	(5,192)	—	—
Kwoiek Creek Resources, L.P. (1)	Canada	50.00%	50.00%	(755)	(1,048)	(12,970)	(12,216)
Mesgi'g Ugju's'n (MU) Wind Farm L.P. (1)	Canada	50.00%	50.00%	8,886	9,156	(6,663)	(3,794)
Innergex Sainte-Marguerite, S.E.C.	Canada	49.99%	49.99%	(2,497)	(2,157)	(11,268)	(8,771)
Innergex Europe (2015) Limited Partnership and its subsidiaries	Canada/ Europe	30.45%	30.45%	(4,409)	(5,478)	(3,080)	4,862
HS Orka hf 2	Iceland	—%	46.10%	2,133	921	—	282,665
Others	Canada	Various	Various	(487)	(17)	(312)	(1,246)
				(3,170)	(5,422)	10,942	312,776

1.The Corporation owns more than 50% of the economic interest in the subsidiary.
2. In 2019, the Corporation sold its wholly-owned subsidiary Magma Energy Sweden A.B. ("Magma Sweden") which owned an equity interest of approximately 53.9% in HS Orka hf, owner of two operating geothermal power plants in Iceland; Svartsengi and Reykjanes.

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

Summarized financial information in respect of each of the Corporation's subsidiaries that has material non-controlling interests is set out below. The summarized financial information below represents amounts before intragroup eliminations.

	Year ended December 31, 2019				
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex Europe
Summary Statements of Earnings and Comprehensive income (loss)					
Revenues	40,175	18,014	62,880	9,283	94,474
Expenses	52,259	19,524	30,717	14,277	108,954
Net (loss) earnings	(12,084)	(1,510)	32,163	(4,994)	(14,480)
Other comprehensive loss	—	—	—	—	(11,199)
Total comprehensive (loss) income	(12,084)	(1,510)	32,163	(4,994)	(25,679)
Net (loss) earnings attributable to:					
Owners of the parent	(6,043)	(755)	23,277	(2,497)	(10,071)
Non-controlling interests	(6,041)	(755)	8,886	(2,497)	(4,409)
	(12,084)	(1,510)	32,163	(4,994)	(14,480)
Total comprehensive (loss) income attributable to:					
Owners of the parent	(6,043)	(755)	23,277	(2,497)	(17,737)
Non-controlling interests	(6,041)	(755)	8,886	(2,497)	(7,942)
	(12,084)	(1,510)	32,163	(4,994)	(25,679)
Summary Statements of Cash Flows					
Net cash inflow from operating activities	15,807	5,000	46,912	1,132	36,509
Net cash (outflow) from financing activities	(10,986)	(1,650)	(35,253)	(527)	(17,690)
Net cash (outflow) inflow from investing activities	(626)	(191)	(14,035)	(215)	3,521
Net increase (decrease) in cash and cash equivalents	4,195	3,159	(2,376)	390	22,340
Distributions paid to non-controlling interests	—	—	11,466	—	—

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

	Year ended December 31, 2018				
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex Europe
Summary Statements of Earnings and Comprehensive income (loss)					
Revenues	50,509	17,899	62,592	11,246	87,016
Expenses	54,681	19,995	29,455	15,561	105,005
Net (loss) earnings	(4,172)	(2,096)	33,137	(4,315)	(17,989)
Other comprehensive (loss) income	—	—	(174)	—	1,130
Total comprehensive (loss) income	(4,172)	(2,096)	32,963	(4,315)	(16,859)
Net (loss) earnings attributable to:					
Owners of the parent	(2,565)	(1,048)	23,981	(2,158)	(12,511)
Non-controlling interests	(1,607)	(1,048)	9,156	(2,157)	(5,478)
	(4,172)	(2,096)	33,137	(4,315)	(17,989)
Total comprehensive (loss) income attributable to:					
Owners of the parent	(2,565)	(1,048)	23,855	(2,158)	(11,602)
Non-controlling interests	(1,607)	(1,048)	9,108	(2,157)	(5,257)
	(4,172)	(2,096)	32,963	(4,315)	(16,859)
Summary Statements of Cash Flows					
Net cash inflow (outflow) from operating activities	8,293	(2,049)	51,709	2,672	(52,272)
Net cash (outflow) inflow from financing activities	(10,537)	(1,592)	(39,901)	(3,070)	58,451
Net cash (outflow) inflow from investing activities	(1,585)	267	(6,312)	(206)	(2,676)
Net (decrease) increase in cash and cash equivalents	(3,829)	(3,374)	5,496	(604)	3,503
Distributions paid to non-controlling interests	—	—	9,202	—	—

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

Summary Statements of Financial Position

	As at December 31, 2019				
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex Europe
Current assets	17,201	5,962	21,356	1,522	54,565
Non-current assets	575,070	167,091	277,945	124,121	888,895
	592,271	173,053	299,301	125,643	943,460
Current liabilities	16,700	7,355	248,264	7,688	100,966
Non-current liabilities	448,022	202,354	20,641	124,010	898,280
Equity (deficit) attributable to owners	82,314	(23,686)	37,059	5,213	(52,706)
Non-controlling interests (deficit)	45,235	(12,970)	(6,663)	(11,268)	(3,080)
	592,271	173,053	299,301	125,643	943,460

Summary Statements of Financial Position

	As at December 31, 2018				
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex Europe
Current assets	20,642	4,306	23,533	1,542	40,787
Non-current assets	587,713	169,408	276,142	126,863	957,524
	608,355	173,714	299,675	128,405	998,311
Current liabilities	17,480	5,428	12,500	6,550	140,042
Non-current liabilities	451,381	191,784	246,394	122,915	888,376
Equity (deficit) attributable to owners	88,218	(11,282)	44,575	7,711	(34,969)
Non-controlling interests (deficit)	51,276	(12,216)	(3,794)	(8,771)	4,862
	608,355	173,714	299,675	128,405	998,311

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

Acquisition of minority interest in Creek Power Inc.

Creek Power Inc.

On May 15, 2018, Innergex acquired the 33.3% interest of Ledcor Power Ltd in Creek Power Inc., a company that indirectly owns the Fitzsimmons Creek, Boulder Creek and Upper Lillooet River hydro facilities located in British Columbia as well as a portfolio of prospective projects for a total consideration of $1,700. Innergex already owned the remaining 67.7% interest in Creek Power Inc. Innergex also owned all the preferred equity and received virtually all of the cash flows generated by the three facilities.

The negative amount of $32,108 previously recorded in non-controlling interest was eliminated as the Corporation now owns 100% of Creek Power Inc. Since the change in ownership did not result in a change of control, the difference between the adjustment to non–controlling interest and the consideration paid was recorded directly in deficit ($33,808).

27. RELATED PARTY TRANSACTIONS

a) 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 CEO, CFO, CIO and all the Senior Vice Presidents and Vice Presidents are key management personnel of the Corporation.

	Year ended December 31	
	2019	2018
Salaries and short-term benefits	6,685	6,073
Attendance fees for members of the Board of Directors	853	738
Performance share plan	1,764	1,769
Share-based payments	64	69
	9,366	8,649

b) Transactions with partners

Related party transactions conducted in the normal course of operations are measured at exchange amount which is the amount established and agreed to by the related parties, unless specific requirements within IFRS require different treatment.

The Corporation's subsidiaries have entered into the following transactions with partners:

- Sainte Marguerite L.P.'s debenture to RRMD (see note 22c)
- Magpie's convertible debenture to the municipality
- Innergex Europe (2015) Limited Partnership's debenture to RRMD
- The Corporation's partner made a loan to Kwoiek Creek Resources L.P.

A $3,000 convertible debenture has no predetermined repayment schedule and matures in January 2025. The convertible debenture, bearing interest at a fixed rate of 15.5%, entitles the Minganie Regional County Municipality to a 30% interest in the facility upon conversion of the debenture on or before January 1, 2025. Early conversion is at the discretion of the Corporation.

A $77,957 debenture was issued by Innergex Europe (2015) Limited Partenership's to RRMD. This debenture carries an interest rate of 8.00% compounded yearly and is payable quarterly if funds are available. The debenture will be repayable in full in 2046.

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

The Corporation's partner in the Kwoiek Creek project made a $3,662 loan to Kwoiek Creek Resources L.P. Under the project agreements, both partners can participate in the project financing. The loan bears a fixed interest rate of 10.07% and matures in 2054.

28. FINANCIAL RISK MANAGEMENT AND FAIR VALUE DISCLOSURES

Fair value disclosures

The following table shows the carrying amounts and fair values of financial assets and financial liabilities, including their levels in the fair value hierarchy. It does not include fair value information for financial assets and financial liabilities not measured at fair value if the carrying amount is a reasonable approximation of fair value.

Further, for the current year the fair value disclosure of lease liabilities is also not required. The Corporation determined that the carrying values of its current financial assets and liabilities, as well as their government-backed securities included in reserve accounts, was within reasonable proximity of their respective fair values due to their shorter-term maturities and high liquidity.

		As at December 31, 2019		As at December 31, 2018	
	Fair value level	Carrying amount	Fair value	Carrying amount	Fair value
Non-current financial assets measured at amortized cost					
Other investments included in other long-term assets	*Level 2*	2,000	2,000	—	—
Non-current financial liabilities measured at amortized cost					
Long-term loans and borrowings	*Level 2*	4,691,669	4,808,403	4,708,397	4,875,075
Derivative financial instruments measured at fair value					
Interest rate swaps	*Level 2*	(83,536)	(83,536)	(53,409)	(53,409)
Foreign exchange forwards	*Level 2*	(24,269)	(24,269)	(32,129)	(32,129)
Power and basis hedges	*Level 3*	27,757	27,757	(4,849)	(4,849)
Inflation provisions	*Level 3*	—	—	982	982
Embedded derivatives	Level 2	—	—	(46,409)	(46,409)

Equity investments

The valuation model is based on market multiples derived from quoted prices of companies comparable to the investee, adjusted for the effect of the non-marketability of the equity securities, and the revenue and EBITDA of the investee. The estimate is adjusted for the net debt of the investee.

Other investments

The valuation model considers the present value of expected payments, discounted using a risk-adjusted discount rate.

Long-term loans and borrowings

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

The fair value of each debt instrument is estimated utilizing standard financial industry practices where future expected cash flows are discounted at discount rates based on the interest rate and credit conditions prevailing in the financial markets as of the valuation date. Notably, for fixed rate instruments, contractual cash flows are discounted at an appropriate yield to maturity. For floating rate instruments, future expected contractual interest rates represent the sum of future expected levels of the reference interest rate index and the instrument’s quoted margin whereas discount rates represent the sum of future expected levels of the reference index and an appropriate discount margin. Appropriate yields to maturity and discount margins are estimated utilizing the available quoted or indicative pricing of individual debt instruments or indices whose credit is deemed comparable to the debt instruments being evaluated.

Interest rate swaps

The fair value is calculated as the present value of the estimated future cash flows. Estimated cash flows are discounted using a yield curve constructed from similar sources and which reflects the relevant benchmark interbank rate used by market participants for this purpose when pricing interest rate swaps. The fair value estimate is subject to a credit risk adjustment that reflects the credit risk of the Corporation and of the counterparty.

Foreign exchange forwards

The fair value is calculated as the present value of the estimated future cash flows, representing the differential between the value of the contract at maturity and the value determined using the exchange rate the financial institution would use if the same contract was renegotiated at the statement of financial position date. The fair value estimate is subject to a credit risk adjustment that reflects the credit risk of the Corporation and of the counterparty, considering the offsetting agreements, as applicable.

Power hedges

The fair value calculation of power and basis hedges gives rise to measurement uncertainty as the power price curves are constructed using various methodologies and assumptions, which consider certain unobservable market data. As at December 31, 2019, the forward power prices used in the calculation of fair value were as follows:

Power hedge:

- ERCOT South hub forward power prices are expected to be in a range of US$8.92 to US$135.37 per MWh between January 1, 2020 and June 30, 2031.

Basis hedge:

- ERCOT South hub forward power prices are expected to be in a range of US$20.74 to US$135.37 per MWh between January 1, 2020 and December 31, 2021;
- Phoebe node forward power prices are derived using a historical spread against the ERCOT South hub of US $23.87 per MWh.

Further information is provided below with regards to the methodology for constructing the forward power price curves.

Phoebe power hedge: The fair value of the power hedge is derived from forward power prices that are not based on observable market data for the entirety of the contracted period. The power ERCOT South hub forward price curves are constructed using various assumptions depending on the following observable market data available as of the valuation date: (1) observable monthly market prices through December 2025 for the ERCOT South hub; (2) a perpetual heat rate based on the calendar year forward electricity price and the NYMEX natural gas calendar strip resulting in calendar year average power prices through December 2030, adjusted for seasonality based on calendar year 2019; and (3) the last year's monthly prices multiplied by a factor of inflation.

Phoebe basis hedge: The fair value of the basis hedge is derived from observable forward power prices at the ERCOT South hub for the duration of the contract period and a Phoebe node forward price curve constructed using various assumptions depending on the following observable market data available as of the valuation date: (1) forward power prices at the ERCOT South hub for the duration of the contract period; (2) historical spread between the ERCOT South hub and the Phoebe node prices from July 2019 onwards ("Observable Period"); and (3) historical spread prior to July 2019 between the ERCOT South hub and a proxy to the Phoebe node, adjusted for the average price differential between the Phoebe node and its proxy during the Observable Period. The fair value estimate is subject to a credit risk adjustment that reflects the credit risk of the Corporation and of the counterparty.

Financial risk management

The Corporation is exposed to a variety of financial risks: market risk (e.g. interest rate, foreign exchange, and power price and others), credit risk and liquidity risk. The Corporation's objective with respect to financial risk management is to secure the long-term internal rate of return of its energy projects by mitigating uncertainty related to the fluctuation of certain key variables.

Management is responsible for establishing controls and procedures to ensure that financial risks are managed within acceptable levels. The Corporation does not use derivative financial instruments for speculative purposes.

a. 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 interest rate, foreign exchange, and power price risks.

(i) Interest rate risk

Interest rate risk is the risk that the future cash flow or fair value of a financial instrument will fluctuate due to changes in market interest rates. Financial assets and liabilities with variable interest rates expose the Corporation to interest rate risk with respect to its cash flow. The risk that the Corporation will realize a loss as a result of a decline in the fair value of any short-term securities included in cash and cash equivalents and short-term investments is limited because these investments, although readily convertible into cash, are generally held-to-maturity.

The Corporation's cash flow exposure to interest rate risk relates principally to floating rate long-term loans and borrowings. Management mitigates this risk by entering into fixed rate financing agreements or interest rate swap agreements related to its floating rate financing agreements. From time to time, the Corporation may enter into bond forward contracts to pre-hedge the interest rate risk related to future debt issuances by locking-in an interest rate during the period leading to the execution of the financing agreement.

The Corporation has designated the following derivative financial instruments as cash flow hedges[1]:

Project	Notional Currency[2]	Variable rate	Swap Rate	Maturity	Early termination option	Notional Amounts December 31, 2019	Notional Amounts December 31, 2018
Corporate							
Innergex	CAD	CDOR	2.18%	2027	2023	20,000	20,000
Innergex	CAD	CDOR	2.33%	2028	2023	30,000	30,000
Innergex	CAD	CDOR	2.33%	2028	2023	52,600	52,600
Innergex	CAD	CDOR	2.33%	2024	2019	20,000	20,000
Innergex	CAD	CDOR	2.30%	2024	2019	20,000	20,000
Innergex	CAD	CDOR	4.25%	2031	2020	33,205	35,182
Innergex	CAD	CDOR	1.89%	2029	2023	20,000	—
Innergex	CAD	CDOR	1.92%	2029	2023	20,000	—
Innergex	CAD	CDOR	2.08%	2034	2029	20,000	—
Innergex	CAD	CDOR	2.12%	2034	2023	20,000	—
Innergex	CAD	CDOR	2.24%	2049	2029	20,000	—
Innergex	CAD	CDOR	2.19%	2049	2029	25,000	—
Alterra	CAD	CDOR	2.16%	2023	None	29,000	29,000
Alterra	CAD	CDOR	2.32%	2023	None	49,000	49,000
Hydroelectric segment							
Ashlu Creek	CAD	CDOR	4.61%	2035	2025	88,219	89,438
Fitzsimmons Creek	CAD	CDOR	2.85%	2041	2021	17,642	18,017
Wind segment							
Rougemont 1	EURO	EURIBOR	1.30%	2032	None	61,822	70,201
Rougemont 2	EURO	EURIBOR	1.30%	2032	None	37,732	42,862
Rougemont 2	EURO	EURIBOR	1.48%	2032	None	34,253	38,909
Vaites	EURO	EURIBOR	1.28%	2032	None	66,178	75,336
Cartier	CAD	CDOR	2.83%	2032	None	530,982	569,361
Mesgi'g Ugju's'n	CAD	CDOR	1.91%	2026	None	84,872	91,464
Yonne	EURO	EURIBOR	0.78%	2031	None	—	69,128
Cholletz	EURO	EURIBOR	2.64%	2030	None	12,778	14,942
Foard City	USD	LIBOR	2.07%	2029	2026	14,956	—
Foard City	USD	LIBOR	2.43%	2029	2026	14,117	—
Solar Segment							
Stardale	CAD	CDOR	3.60%	2032	None	71,666	75,141
Phoebe	USD	LIBOR	2.63%	2019	None	—	214,679
Phoebe	USD	LIBOR	3.07%	2037	2026	135,435	142,255
Kokomo	USD	LIBOR	1.85%	2026	None	5,603	6,200
Spartan	USD	LIBOR	2.31%	2024	None	12,237	13,403
						1,567,297	1,787,118

1. The Corporation applies a hedge ratio of 1:1 and determines the existence of an economic relationship between the hedging instrument and hedged item based on the reference interest rates, maturities and the notional amounts. The Corporation assesses whether the derivative designated in each hedging relationship is expected to be effective in offsetting changes in cash flows of the hedged item using the hypothetical derivative method.
2. USD swaps are converted at a fixed rate of CAD 1.2988 and EURO swaps are converted at a fixed rate of CAD 1.4583

Interest rate hedging instruments entered into during the year ended December 31, 2019

On May 8, 2019 and June 5, 2019, the Corporation entered into eight US$ denominated interest rate swap agreements to mitigate the interest rate risk related to the Foard City term loan. The notional amounts of these contracts as at December 31, 2019 totals US$22,383 ($29,073) and will mature in 2029. The fair value is based on Level 2 valuation techniques. The Corporation designated the interest rate swaps as cash flow hedges for accounting purposes.

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

On July 18, 2019 and July 22, 2019, the Corporation entered into six interest rate swap agreements to mitigate the interest rate risk on the revolving credit facilities held by the Corporation. The notional amounts of these contracts as at December 31, 2019 totals $125,000 and mature between 2029 and 2049. The fair value is based on Level 2 valuation techniques. The Corporation designated the interest rate swaps as cash flow hedges for accounting purposes.

On October 9, 2019, Innergex terminated the two interest rate swaps for the Yonne project for a cost of €2,836 ($4,144) corresponding to its net book value at that date. The loss accumulated in the Other Comprehensive Income will be amortized until the end of 2031, the period remaining to the swaps prior to termination. As of December 31, 2019, the unamortized balance aggregates to €2,254 ($3,380).

On December 20, 2019, due to the debt refinancing of the Stardale project, the Corporation terminated the two interest rate swap agreements relating to this project and entered into two new interest rate swap agreements covering the extended maturity period of the debt. The fair value of the new interest rate swaps was equivalent to the fair value of the terminated swaps. The notional amounts of these agreements as at December 31, 2019 total $71,666 and will mature in 2032. The Corporation designated the interest rate swaps as cash flow hedges for accounting purposes.

Sensitivities

A reasonably possible change of 10 basis points in interest rates at the reporting date would have increased (decreased) earnings (loss) and other comprehensive income (loss) by the amounts shown below. This analysis assumes that all other variables remain constant.

	Earnings (loss)		Other comprehensive income (loss)	
	10 bps increase	10 bps decrease	10 bps increase	10 bps decrease
December 31, 2019				
Interest rate swaps	600	(719)	9,555	(9,445)
December 31, 2018				
Interest rate swaps	1,044	(1,058)	8,821	(8,849)

(ii) Foreign exchange risk

Foreign exchange risk is the risk that future cash flows or fair value of a financial instrument will fluctuate because of changes in foreign exchange rates, namely the U.S. dollar and Euro against the Canadian dollar.

The Corporation is exposed to transactional foreign currency risk to the extent that there is a mismatch between the currencies in which sales, purchases, receivables and borrowings are denominated and the respective functional currencies of the Corporation and its subsidiaries. Other than during the construction of renewable energy projects, such transactional risks are limited given the majority of transactions are made in the respective functional currencies of the Corporation or its subsidiaries.

The Corporation has subsidiaries in Europe for which the revenues, net of the expenses incurred, are repatriated to Canada. The Corporation's foreign exchange forwards are denominated in Euro. Repatriated funds that are not used to service the Euro denominated foreign exchange forwards are converted into Canadian dollars at the exchange rate in effect on the conversion date.

The Corporation has designated the following derivative financial instruments as net investment hedges[1]:

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

Contracts	Maturity	Early termination option	Notional Amounts December 31, 2019	December 31, 2018
Contracts used to hedge the foreign exchange risk				
Foreign exchange forwards amortizing until 2041, allowing conversion at a fixed rate of CAD 1.7332/Euro	2020	none	154,653	156,364
Foreign exchange forwards amortizing until 2042, allowing conversion at a fixed rate of CAD 1.7340/Euro	2020	none	46,377	47,949
Foreign exchange forwards amortizing until 2041, allowing conversion at a fixed rate of CAD 1.6850/Euro	2021	none	103,630	111,945
Foreign exchange forwards amortizing until 2043, allowing conversion at a fixed rate of CAD 1.7654/Euro	2021	none	155,873	159,538
Foreign exchange forwards amortizing until 2043, allowing conversion at a fixed rate of CAD 1.7804/Euro	2021	none	75,002	77,896
			535,535	553,692

1. The applies a hedge ratio of 1:1. The Corporation determines the existence of an economic relationship between the hedging instrument and hedged item based on the currency and notional amounts. The Corporation assesses whether the derivative designated in each hedging relationship is expected to be effective in offsetting changes in cash flows of the hedged item using the hypothetical derivative method.

Sensitivities

A reasonably possible 1% strengthening (weakening) of the Euro against the Canadian Dollar at the reporting date would have increased (decreased) earnings (loss) and other comprehensive income (loss) by the amounts shown below. This analysis assumes that all other variables remain constant.

	Earnings (loss)		Other comprehensive income (loss)	
	1% increase	1% decrease	1% increase	1% decrease
December 31, 2019				
Foreign exchange forwards	(4,852)	4,855	535	(537)
December 31, 2018				
Foreign exchange forwards	(4,710)	4,705	453	(447)

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

(iii) Power price risk

Power price risk is the risk that future cash flows or fair value of a financial instrument will fluctuate because of changes in market prices of electricity.

Most sales of electricity are made pursuant to long-term agreements where the offtakers are committed to take and pay for the total production at pre-determined prices, up to certain annual limits and generally subject to annual inflation. For some of the Corporation's facilities, power generated is sold on the open market and supported by power hedges to address market price risk exposure.

Phoebe power hedge

On July 2, 2018, the Corporation acquired, through its subsidiary, Alterra Power Corp, the assets of the Phoebe solar project, including a 12-year power hedge, effective from July 1, 2019 to June 30, 2031. On the acquisition date, the power hedge was measured at its fair value of US$16.1 million. As of that date, it was designated for hedge accounting purposes. Subsequent changes in the fair value of the power hedge were mainly recognized through other comprehensive income. To determine the fair value of the Phoebe power hedge and support the hedge effectiveness testing for hedge accounting purposes, forward prices of the ERCOT South Hub and the Phoebe Node were required, however quoted forward market prices at the hub were limited and forward prices were unavailable at the node. The Phoebe project started delivering energy at the node in June 2019 and commenced delivering energy under the power hedge on July 1, 2019. Until September 30, 2019, the price differential risk between the hub and the node (or "basis differential" risk) had been assumed negligible for this purpose until evidence that changes in the Phoebe Node prices were not closely aligned with changes in the ERCOT South Hub prices. In light of this new information, Management revised, effective October 1, 2019, its methodology to derive forward node prices in order to more accurately reflect the basis differential risk, which resulted in the Phoebe power hedge no longer meeting the hedge effectiveness criteria.

Since the forecasted transactions are still expected to occur, the cumulative changes in fair value, totaling $36,532 as at December 31, 2019, recognized in accumulated other comprehensive income at the hedge relationship cessation date will remain and be reclassified to revenue over the remaining term of the power hedge. Subsequent changes in the fair value of the derivative instrument will be recognized in the consolidated statement of earnings, as unrealized net loss (gain) on financial instruments.

Sensitivities

A reasonably possible change of 10% in the forward ERCOT South Hub prices at the reporting date would have increased (decreased) earnings (loss) and other comprehensive income (loss) by the amounts shown below. This analysis assumes that all other variables remain constant.

	Earnings (loss)		Other comprehensive income (loss)	
	10 % increase	10% decrease	10 % increase	10% decrease
December 31, 2019				
Power hedge	(18,249)	18,195	—	—
December 31, 2018				
Power hedge	—	—	(21,069)	21,068

Phoebe basis hedge

On August 2, 2019, the Corporation entered into a 2-year basis hedge, effective November 1, 2019 to December 31, 2021, in order to mitigate the basis differential risk. The basis hedge is accounted for at fair value, with subsequent changes being recognized in the consolidated statement of earnings as unrealized net loss (gain) on derivative financial instruments. The change in fair value recognized as an unrealized net loss on derivative financial instruments amounted $47,977 in fiscal 2019.

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

Sensitivities

A reasonably possible change of 100bps in the spread between the forward ERCOT South Hub and the Phoebe node prices at the reporting date would have increased (decreased) earnings (loss) and other comprehensive income (loss) by the amounts shown below. This analysis assumes that all other variables remain constant.

	Earnings (loss)		Other comprehensive income (loss)	
	100 bps increase	100 bps decrease	100 bps increase	100 bps decrease
December 31, 2019				
Basis hedge	(1,487)	1,487	—	—
December 31, 2018				
Basis hedge	—	—	—	—

(iv) Hedge accounting

A fundamental review and reform of major interest rate benchmarks is being undertaken globally. There is uncertainty as to the timing and the methods of transition for replacing existing benchmark interbank offered rates (IBORs) with alternative rates. As a result of these uncertainties, significant accounting judgment is involved in determining whether certain hedge accounting relationships that hedge the variability of foreign exchange and interest rate risk due to expected changes in IBORs continue to qualify for hedge accounting as at December 31, 2019. IBOR continues to be used as a reference rate in financial markets and is used in the valuation of instruments with maturities that exceed the expected end date for IBOR. Therefore, the Corporation believes the current market structure supports the continuation of hedge accounting as at December 31, 2019.

All the hedging instruments are accounted for in the current or non-current portion of derivative financial instruments in the consolidated statements of financial position. As at December 31, 2019, the following items were designated as hedging instruments to mitigate the interest rate risk, the power price risk and the foreign exchange risk:

		Carrying amount of the hedging instrument	
	Notional amount of the hedging instrument	Assets	Liabilities
Cash-flow hedges:			
Interest rate risk			
Interest rate swaps	1,567,292	2,003	(85,491)
Net investment hedges:			
Foreign exchange risk			
Foreign exchange forwards	63,775	1,371	(3,767)

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

The following table summarizes the impact of hedge ineffectiveness and hedging gains or losses as at December 31, 2019:

	Changes in fair value of the hedging instrument recognized in other comprehensive income	Hedge ineffectiveness recognized in profit or loss	Amount reclassified from the cash flow hedge reserve to profit or loss
Cash-flow hedge:			
Interest rate risk			
Interest rate swaps	(38,888)	(792)	430
Power price risk			
Power hedge [1]	63,139	1,274	1,133
Hedge of net investment in a foreign operation:			
Foreign exchange risk			
Foreign exchange forwards	2,138	(39)	195

1. The balance of cash flow hedge reserve relating to power price risk for which hedge accounting is no longer applied is $36,532.

Ineffectiveness is accounted for in the unrealized net loss (gain) on financial instruments in the consolidated statements of earnings.

For the hedge relationships covering the interest rate risk and the foreign exchange risk, ineffectiveness can result from the credit valuation adjustment applied to the fair value of hedging derivatives as well as the designation of hedging derivatives with a non-zero fair value at the inception of a hedging relationship.

b. Credit risk

Credit risk is the risk of financial loss to the Corporation that may arise from a party's failure to meet its contractual obligations. The maximum exposure to credit risk at the reporting date is the carrying value of the Corporation's financial assets.

(i) Cash and cash equivalents, restricted cash and reserves

As at December 31, 2019, the Corporation was holding cash and cash equivalents, restricted cash (Note 13) and reserves included in other long-term assets (Note 15). The Corporation limits its counterparty credit risk on these assets by dealing with highly rated, large Canadian financial institutions and, to a lesser degree, at major U.S. and European financial institutions. The Corporation recorded no impairment on these financial assets.

(ii) Accounts receivable

Most of the Corporation's trade receivables relate to electricity sold to public utilities, including Hydro-Québec, British Columbia Hydro and Power Authority, Hydro One Inc. and its affiliates, Idaho Power Company and Électricité de France. These utility companies are highly rated by the various rating agencies.

Accounts receivable also include commodity taxes and investment tax credits which are receivable from governments, mainly in relation with the development and construction of projects.

As at December 31, 2019, $3,616 ($62 in 2018) of trade and other receivables were more than 90 days overdue and a total write-off of impaired receivables of $438 ($314 in 2018) was recorded during the year. Given that expected credit losses are minimal, the expected credit losses by trade accounts receivable aging have not been presented.

(iii) Derivatives

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

A counterparty is deemed qualified to transact with the Corporation in interest rate or currency hedging transactions if and so long as the counterparty is a bank, insurance company, investment dealer, investment bank or other financial institution, or any affiliate of any of them whose long term debt is rated 'A-'(stable) (or its equivalent) or better from any of (i) Standard & Poor's Corporation (ii) Moody's Investor Services Inc. (iii) DBRS Limited or (iv) Fitch Ratings.

c. 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 hedging instruments have embedded early termination options. 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 expenses, as a negative value would be the result of an environment in which actual rates are more beneficial than the rates embedded in the swap.

The Corporation has a negative working capital of $335,721 as at December 31, 2019 (negative working capital of $413,015 in 2018). If necessary, the Corporation can use its revolving credit facilities of which $161,922 was available as at December 31, 2019 ($143,455 in 2018). 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 15) and is covered by insurance plans. The Corporation considers its current level of working capital to be sufficient to meet its needs.

The following table presents the contractual cash flows of the financial liabilities:

	Less than 1 year	Between 1 year and 5 years	Over 5 years	Total
Non-derivatives financial				
Accounts payable and other payables	176,157	—	—	176,157
Long-term loans and borrowings	662,155	2,013,810	4,407,938	7,083,903
Other liabilities	761	1,055	22,066	23,882
Lease liabilities	7,841	39,462	155,494	202,797
Derivative financial liabilities				
Interests rate swaps	7,637	27,501	22,624	57,762
Foreign exchange forwards	31,903	54,626	—	86,529
Power Hedge	17,398	(5,080)	(141,112)	(128,794)
Basis Hedge	18,158	18,108	—	36,266
Total	922,010	2,149,482	4,467,010	7,538,502

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

29. COMMITMENTS AND CONTINGENCIES

a. Power Purchase Agreements

Quebec facilities

Under PPAs with terms varying from 20 to 25 years and expiring between 2021 and 2039, Hydro-Québec agreed to purchase all of the electrical energy produced by the facilities and wind farms located in the Province of Quebec. Certain facilities have an agreed maximum quantity of electricity and a minimum quantity of electricity to deliver during each of the consecutive 12-month periods. Expiring PPA's are being renegotiated under the renewal rights of the Corporation.

British Columbia facilities

Under PPAs with terms varying from 20 to 40 years and expiring between 2023 and 2057, British Columbia Hydro and Power Authority agreed to purchase all of the electrical energy produced by the facilities located in the Province of British Columbia.

On April 16, 2018, the Corporation and the Sekw'el'was Cayoose Creek Band announced that they reached an agreement with the British Columbia Hydro and Power Authority ("BC Hydro") for the renewal of the Walden North Facility's electricity purchase agreement (the "Walden PPA"). The renewed Walden PPA became effective as of April 1, 2018 and has a 40-year term. The Walden PPA is subject to approval by the British Columbia Utilities Commission ("BCUC").

On April 16, 2018, the Corporation announced that it reached an agreement with BC Hydro for the renewal of the electricity purchase agreement of the Brown Lake Facility for a 40-year term (the "Brown Lake PPA"). The renewed Brown Lake PPA became effective as of April 1, 2018 and is subject to approval by the BCUC.

By Order G-278-19, dated November 8, 2019 ("BCUC Order"), in the absence of an updated and approved Integrated Resource Plan from BC Hydro ("IRP"), the BCUC declined to make any determination with regards to whether the Walden PPA and the Brown Lake PPA are, as of the date of the BCUC Order, in the public interest. However, the BCUC is prepared to consider accepting PPA renewals for periods shorter than 40 years to allow for the conclusion of BC Hydro's next IRP proceeding. The parties to the Brown Lake PPA are considering resubmitting to the BCUC a restructured Brown Lake PPA with a term of no more than three years from the date of the BCUC Order, whereas the parties to the Walden PPA are considering, for the time being, not to resubmit a restructured Walden PPA to the BCUC.

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 produced by the facilities located in Ontario.

Europe facilities

Under PPAs with terms of 15 years expiring between 2024 and 2032, Électricité de France and S.I.C.A.E Oise agreed to purchase all of the electrical energy produced by the facilities located in France.

USA facilities

Under a PPA with a 35-year term and expiring in 2030, Idaho Power Company agreed to purchase all of the electricity produced by Horseshoe Bend Hydroelectric Corporation.

Under PPAs with terms of 20 to 25 years expiring between 2036 and 2042, clients agreed to purchase all of the electricity produced by Kokomo and Spartan.

b. Other Commitments

(i) Hydroelectric facilities

The Corporation and its subsidiaries entered into royalties and other commitments related to surrounding municipalities, land owners and the operation of the hydroelectric facilities.

Ashlu Creek facility

The ownership of the assets of the project will be transferred to a First Nation in 2049 for a nominal financial consideration.

Boulder Creek facility

40% of the Corporation's ownership of the project will be transferred to the First Nation partner in 2057 for no financial consideration.

Big Silver facility

A 50% ownership of the assets of the project will be transferred to one of the First Nations partners in 2056 for no financial consideration.

Glen Miller facility

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.

Harrison Hydro L.P.

The ownership of Douglas Creek Project L.P. and Tipella Creek Project L.P. will be transferred to a First Nation in 2069 for no financial consideration.

Kwoiek Creek facility

The Corporation's ownership of the project will be transferred to the First Nation partner in 2054 for no financial consideration.

Rutherford Creek facility

Rutherford L.P. agreed to make payments to the former owners, following the expiry of the Rutherford Creek PPA in 2024. 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. 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 term loan.

Tretheway facility

50% of the Corporation's ownership will be transferred to a First Nation in 2055 for no financial consideration.

Upper Lillooet facility

40% of the Corporation's ownership of the project will be transferred to the First Nation partner in 2057 for no financial consideration.

(ii) Wind farm facilities

The Corporation and its subsidiaries entered into royalties and other commitments related to amounts to set aside for the dismantling of wind farm components, commitments to surrounding municipalities and land owners and the operation of the wind farms.

Europe

The French subsidiaries entered into commitments related to land leases, maintenance and management contracts for the operations of the wind farms.

(iii) Solar facilities

Stardale Solar L.P. and Phoebe Energy Project LLC have entered into contracts for the operations and maintenance of the respective solar farms.

Hillcrest Solar I, LLC has entered into a transformer engineering, procurement, and supply agreement with GE Prolec Transformers Inc. to construct the solar project.

c. Summary of commitments

As at December 31, 2019, the expected schedule of commitment payments is as follows:

Year of expected payment	Under 1 year	1 to 5 years	Thereafter	Total
Purchase obligations	53,649	142,182	276,622	472,453
Operating lease contracts	8,892	44,214	19,763	72,869
Total	62,541	186,396	296,385	545,322

d. Contingencies

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.

On March 23, 2017, the Comptroller of the Water Rights issued adjusted rental statements to the Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012 for an amount of $3,300 in aggregate regarding water rental rates to be charged under the Water Act. The amount claimed was paid under protest and Harrison Hydro L.P. and its subsidiaries filed a notice of appeal of the decision to the Environmental Appeal Board.

On July 26, 2019, the Environmental Appeal Board of British Columbia rendered a decision granting the appeal and ordering the Comptroller of Water Rights to reimburse to each of the Limited Partnerships its proportionate share of the adjusted water rental amounts of $3,181 overcharged to Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012. On November 22, 2019, the Environmental Appeal Board of British Columbia rendered another decision confirming that the sum will accrue interest starting June 28, 2017 until the date it is refunded. On January 20, 2020, the Comptroller of Water Rights filed with the Supreme Court of British Columbia a petition for judicial review of the Environmental Appeal Board's order to return the amount in water rental fees to Harrison Hydro L.P. and its subsidiaries, with interest. On January 31, 2020, the Comptroller of Water Rights transferred an amount of $3,318, representing the principal of $3,181 with interest accrued between June 28, 2017 and January 31, 2020, to a trust account established by Harrison Hydro L.P. and its subsidiaries' external legal counsel, bearing interest in favor of the Appellants. The Corporation recognized the amount in the fiscal 2019 consolidated statements of earnings against Operating expenses.

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

30. CAPITAL DISCLOSURES

The Corporation's strategy in managing its capital is: (i) to develop or acquire high-quality renewable power production facilities that generate sustainable and stable cash flows, with the objective of achieving a high return on invested capital, and (ii) to distribute a stable dividend.

The Corporation seeks to achieve its objectives by:

- Maintaining the generating capacity and enhancing the operation of its hydroelectric facilities, wind farms and solar farms; and
- Acquiring and developing new renewable 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 amounts on an annual basis in major maintenance reserve in order to fund any major maintenance of hydroelectric facilities, wind farms or solar 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 power reserve. This reserve could be used in the event that the net available cash for any given year is less than expected, due to normal changes in hydrology or wind conditions or other unpredictable factors.

The Corporation's capital is composed of long-term loans and borrowings and shareholders' equity. Total capital amounts to $5,311,015 at year-end.

The Corporation uses equity primarily to finance the development of projects. The Corporation uses long-term loans and borrowings 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, development of projects, expenses on prospective projects and other capital expenditures will be financed out of cash generated from the Corporation's operating facilities, borrowings and/or issuance of additional equity. To the extent that external sources of capital, including issuance of additional securities of the Corporation, become limited or unavailable, the Corporation's ability to make necessary capital investment to construct new or maintain existing project facilities will be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion.

Under the terms of the Revolving credit facilities, 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. As at December 31, 2019, the Corporation and its subsidiaries have met all material financial and non-financial conditions, unless indicated below, related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements, trust indentures, 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. As at December 31, 2019, Mesgi'g Ugju's'n project was in default of its credit agreement. A breach was triggered by the bankruptcy of a supplier considered a major project participant under the credit agreement. A waiver has been obtained and was subsequently extended until March 31, 2020. A plan was put in place to ensure the continuity of the operations of the project. Ongoing dialogue and reporting are provided to the project Lenders until this situation is resolved. The project was in compliance of financial covenants. As lender has the right to request repayment, the loan was reallocated to the current portion of long-term loans and borrowings.

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.

31. SEGMENT INFORMATION

Operating segments

The Corporation produces and sells electricity generated by its hydroelectric, wind and solar facilities to publicly-owned utilities or other creditworthy counterparties. The Corporation's Management analyzes the results and manages operations based on the type of technology, resulting in different cost structures and skill set requirements for the operating teams. The Corporation consequently has three operating segments: (a) hydroelectric power generation (b) wind power generation and (c) solar power generation.

During the year ended December 31, 2019, concurrent with reaching an agreement to sell, and the subsequent sale of, its ownership interests in HS Orka, the Corporation's geothermal power generation segment has been reclassified as discontinued operations (see Note 4).

The Corporation's Management evaluates the performance of its operating segments based on revenues and Adjusted EBITDA. During the year, Management revised its operating segments disclosure to better reflect how it evaluates the performance of its operating segments. Certain corporate allocations (such as general and administrative expenses) that were previously made were discontinued to enhance discernment of the operating performance from the corporate performance. In addition, through emphasizing on certain measures, the revised disclosure clarifies how Management evaluates the performance of its operating segments. The Corporation's investments in joint ventures and associates have also increased significantly during 2018 following certain business acquisitions. As such, by including the contribution from joint ventures and associates to the key performance measures, the revised disclosure better reflects the Corporation's recent structural changes. Certain of the comparative figures have been restated to conform with the revised presentation.

"Revenues Proportionate" are Revenues plus Innergex's share of Revenues of the operating joint ventures and associates. "Adjusted EBITDA" represents net earnings (loss) before income tax expenses, finance cost, depreciation and amortization, adjusted to exclude other net expenses, share of (earnings) loss of joint ventures and associates, and unrealized net (gain) loss on financial instruments. "Adjusted EBITDA Proportionate" represents Adjusted EBITDA plus the Corporation's share of Adjusted EBITDA of the operating joint ventures and associates. "Adjusted EBITDA Margin" represents Adjusted EBITDA divided by revenues. Adjusted EBITDA, Adjusted EBITDA Proportionate and Adjusted EBITDA Margin are not recognized measures under IFRS and have no standardized meaning prescribed by IFRS. They may therefore not be comparable to similar measures presented by other issuers. Readers are cautioned that Adjusted EBITDA, Adjusted EBITDA Proportionate and Adjusted EBITDA Margin should not be construed as an alternative to net earnings (loss), as determined in accordance with IFRS.

Except for Adjusted EBITDA, Adjusted EBITDA Proportionate and Adjusted EBITDA Margin described above, the accounting policies for these segments are the same as those described in the significant accounting policies. The Corporation accounts for inter-segment and management sales at the carrying amount.

Year ended December 31, 2019 Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	218,918	304,724	33,400	557,042
Innergex's share of revenues of joint ventures and associates	64,761	37,020	2,118	103,899
Segment Revenues Proportionate	283,679	341,744	35,518	660,941
Segment Adjusted EBITDA	170,023	253,606	31,034	454,663
Innergex's share of Adjusted EBITDA of joint ventures and associates	48,011	21,619	954	70,584
Segment Adjusted EBITDA Proportionate	218,034	275,225	31,988	525,247
Segment Adjusted EBITDA Margin	78%	83%	93%	82%

As at December 31, 2019	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	188,559	228,999	15,582	433,140
Acquisition of property, plant and equipment during the period	2,102	12,753	954	15,809
Transfer of assets upon commissioning	—	526,658	318,429	845,087

1. Segment totals include only operating projects.

Year ended December 31, 2018 Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	238,724	223,579	19,115	481,418
Innergex's share of revenues of joint ventures and associates	53,816	28,569	883	83,268
Segment Revenues Proportionate	292,540	252,148	19,998	564,686
Segment Adjusted EBITDA	188,476	186,281	17,604	392,361
Innergex's share of Adjusted EBITDA of joint ventures and associates	41,162	16,454	(244)	57,372
Segment Adjusted EBITDA Proportionate	229,638	202,735	17,360	449,733
Segment Adjusted EBITDA Margin	79%	83%	92%	82%

As at December 31, 2018	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	205,483	187,156	17,574	410,213
Acquisition of property, plant and equipment during the year	8,368	803	386	9,557

1. Segment totals include only operating projects.

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

Segment Adjusted EBITDA and Adjusted EBITDA Margin are reconciled to the most comparable IFRS measure, namely, net earnings (loss) from continuing operations, in the following table:

	Year ended December 31	
	2019	2018
Segment Adjusted EBITDA	454,663	392,361
Unallocated expenses:		
General and administrative	32,583	23,463
Prospective projects	12,905	16,719
Adjusted EBITDA	409,175	352,179
Share of earnings of joint ventures and associates	(36,469)	(47,596)
Unrealized net loss (gain) on financial instruments	49,933	(12,958)
Other net (revenues) expenses	(104,643)	12,183
EBITDA	500,354	400,550
Finance costs	231,766	195,834
Depreciation and amortization	194,579	151,256
Impairment of project development costs	8,184	—
Provision for income taxes	118,851	27,245
Net (loss) earnings from continuing operations	(53,026)	26,215

Geographic segments

As at December 31, 2019, excluding its investments in joint ventures and associates which are accounted for as equity method, the Corporation had interests in the following operating assets: 29 hydroelectric facilities, six wind farms and one solar farm in Canada, 15 wind farms in France and one hydroelectric facility, one wind farm and three solar farms in the United States. The Corporation operates in four principal geographical areas, which are detailed below:

	Year ended December 31	
	2019	2018
Revenues		
Canada	435,069	387,679
France	94,474	87,016
United States	27,499	6,723
	557,042	481,418

As at	December 31, 2019	December 31, 2018
Non-current assets, excluding derivatives financial instruments and deferred tax assets [1]		
Canada	3,629,942	3,757,207
France	891,764	956,214
United States	1,293,983	555,350
Chile	142,268	154,299
	5,957,957	5,423,070

1. Includes the investments in joint ventures and associates

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

Major Customers

A major customer is defined as an external customer whose transactions with the Corporation amount to 10% or more of the Corporation's annual revenues. The Corporation has identified three major customers. The sales of the Corporation to these major customers are the following:

Major customer	Segment	Year ended December 31	
		2019	2018
British Columbia Hydro and Power authority	Hydroelectric generation	158,197	170,048
Hydro-Québec	Hydroelectric and wind power generation	249,004	185,088
Électricité de France	Wind power generation	91,701	84,484
		498,902	439,620

32. SUBSEQUENT EVENTS

Strategic Alliance and private placement with Hydro-Québec

On February 6, 2020, the Corporation announced that it formed a Strategic Alliance with Hydro-Québec to accelerate its growth strategies. Hydro-Québec also committed an initial $500,000 for future co-investments with the Corporation.

Hydro-Québec invested $661,000 through a Private Placement of Innergex common shares at a price of $19.08 per share, representing a total of 34,637,000 shares. With this Private Placement, Hydro-Québec is now a key strategic investor in the Corporation holding 19.9% of the issued and outstanding common shares on a non-diluted basis.

On February 7, 2020, the Corporation reimbursed $391,588 of the revolving credit facilities and, on February 14, 2020, reimbursed the remaining amount of the revolving credit facilities representing $142,547, totaling $534,135.

33. COMPARATIVE FIGURES

Certain reclassifications have been made to the prior year's financial statements to enhance comparability with the current year's consolidated financial statements.

As a result, certain line items have been amended in the consolidated statement of financial position, consolidated statement of earnings and other comprehensive loss, consolidated statement of changes in equity and consolidated statements of cash flows, and the related notes to the financial statements. Comparative figures have been adjusted to conform to the current year's presentation.

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

SHAREHOLDER INFORMATION

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Transfer Agent and Registrar

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents, please contact:	***AST Trust Company (Canada)*** 2001 Robert-Bourassa, Suite 1600 Montreal QC H3A 2A6 Tel. 1 800 387.0825 416 682.3860 inquiries@astfinancial.com

Common Shares - TSX: INE

Innergex Renewable Energy Inc. had 139,405,832 common shares outstanding as at December 31, 2019, with a closing price of $16.86 per share.

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 $0.902 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, 2021.

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 redeemable by the Corporation since January 15, 2018.

Convertible Debentures - TSX: INE.DB.B

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for an aggregate principal amount of $150.0 million, bearing interest at a rate of 4.75% per annum, payable semi-annually on June 30 and December 31 of each year, commencing on December 31, 2018. The debentures are convertible at the holder's option into Innergex common shares at a conversion price of $20.00 per share, representing a conversion rate of 50 common shares per each thousand dollars of principal amount of debentures. The debentures will mature on June 30, 2025 and will not be redeemable before June 30, 2021.

Convertible Debentures - TSX: INE.DB.C

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for an aggregate principal amount of $143.75 million, bearing interest at a rate of 4.65% per annum, payable semi-annually on October 31 and April 1 of each year, commencing on April 30, 2020. The debentures are convertible at the holder's option into Innergex common shares at a conversion price of $22.90 per share, representing a conversion rate of 43.6681 common shares per each thousand dollars of principal amount of debentures. The debentures will mature on October 31, 2024 and will not be redeemable before October 31, 2022.

Credit Rating by Standard & Poor's

Innergex Renewable Energy Inc.	BBB-
Series A Preferred Shares	P-3
Series C Preferred Shares	P-3

Dividend

On February 27, 2020, the Board of Directors announced an increase of $0.02 in the annual dividend that the Corporation intends to distribute to its shareholders of common shares. This increase, raising the annual dividend from $0.70 to $0.72, payable quarterly, reflects the execution of the Corporation's strategy for building shareholder value. This is the seventh consecutive $0.02 annual dividend increase.

Dividend Reinvestment Plan (DRIP)

Innergex Renewable Energy Inc. offers a Dividend Reinvestment Plan (DRIP) for its shareholders of common shares. This plan enables eligible holders of common shares to acquire additional common shares of the Corporation by reinvesting all or part of their cash dividends. For more information about the Corporation's DRIP, please visit our website at innergex.com or contact the DRIP administrator: AST Trust Company (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.

Independent Auditor

KPMG LLP

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Pour la version papier, écrivez-nous à info@innergex.com

INNERGEX

Renewable Energy.
Sustainable Development.

TIME FOR OPTIMISM

The transition to a carbon-free economy is within our reach. More than ever, Innergex is focusing its actions towards fighting climate change.

We are building a better world with renewable energy, and that is why we can believe in a prosperous future for all of us.

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