INNERGEX

Annual Report 2022

For more than 30 years, Innergex Renewable Energy Inc. has believed 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, solar farms and energy storage facilities, Innergex is convinced that renewable energy will lead the way to a better world. Innergex operates in Canada, the United States, France and Chile and follows a sustainable development philosophy that balances people, our planet and prosperity. The Corporation's shares are listed on the Toronto Stock Exchange ("TSX") under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures are listed under the symbols INE.DB.B and INE.DB.C.

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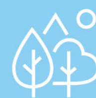
Building a Better World with Renewable Energy

Innergex's team achieves its mission with a sustainable business model that balances People, our Planet and Prosperity.

People

We are a team of passionate individuals who build strong partnerships with local communities.



Planet

We believe that renewable energy is part of the solution to climate change.

Prosperity

We generate value for our employees, our shareholders, our partners and our host communities.

At a Glance

538	84	4	40	35	8	1
employees	clean energy facilities	countries	run-of-river hydro facilities	wind facilities	solar facilities	battery energy storage facility

4,184 MW
of net installed capacity

$8.6 B
Total Assets

10,792 GWh
of proportionate energy produced

A Year in Highlights

January	Acquisition of San Andrés SpA, a 50.6 MW solar facility in Chile
February	Closing of $172.5 million bought deal equity financing and $37 million concurrent private placement
March	Sale of the Shannon wind facility in Texas Launch of a partnership in a Hydrogen Research Chair with the Université du Québec à Trois-Rivières
April	Appointment of a new Chief Financial Officer
May	Two battery energy storage projects initiated in Chile for which battery systems were procured
June	Acquisition of Aela, three wind facilities in Chile for 332 MW of installed capacity Innergex ranks 2nd in Canada's Best 50 Corporate Citizens of 2022 by Corporate Knights
July	Commissioning of Innergex's first stand-alone battery energy storage facility in France
August	Completion of Innergex's Chilean portfolio refinancing with the issuance of CAN$912.6 million green bonds in Chile Signing of a long-term power purchase agreement for the Boswell Springs wind project in Wyoming, USA
September	Innergex holds its 2022 Investor Day
October	Acquisition of the remaining interests in Innergex's wind portfolio in France adding 98.7 MW of net installed capacity
November	Innergex issue its first Climate Assessment Report aligned with the Task Force on Climate-related Financial Disclosures ("TCFD")
December	Innergex receives bronze parity certifications by Women in Governance Acquisition of the remaining interests in Innergex's Mountain Air wind portfolio in Idaho adding 52 MW of net installed capacity

Key Figures

Innergex measures its performance using key performance indicators ("KPIs"). Innergex believes that these indicators are important, as they provide management and the reader with additional information about its production and cash-generating capabilities, its ability to pay dividends and fund its growth.

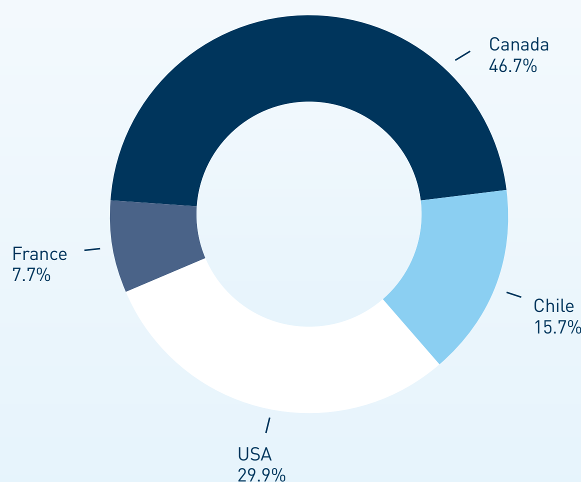
These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Production KPIs	Financial KPIs
Production in comparison with Long-Term Average ("LTA") in megawatt/hours ("MWh") and gigawatt/hours ("GWh")	Revenues and Revenues Proportionate
Production and Production Proportionate	Adjusted EBITDA and Adjusted EBITDA Proportionate
	Adjusted Net Earnings (Loss)
	Free Cash Flow
	Payout Ratio

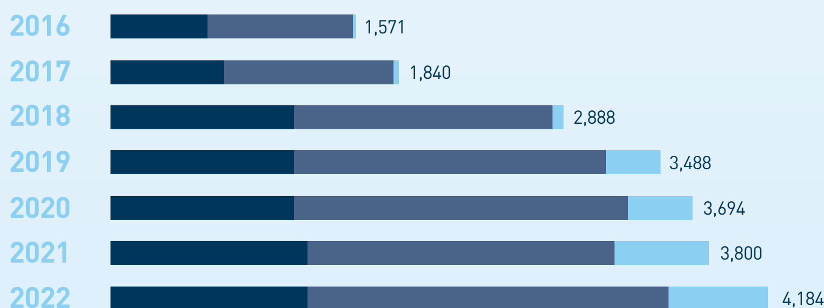
Operational Key Performance Indicators

As at February 22, 2023, the Corporation has four geographic segments and three operating segments.

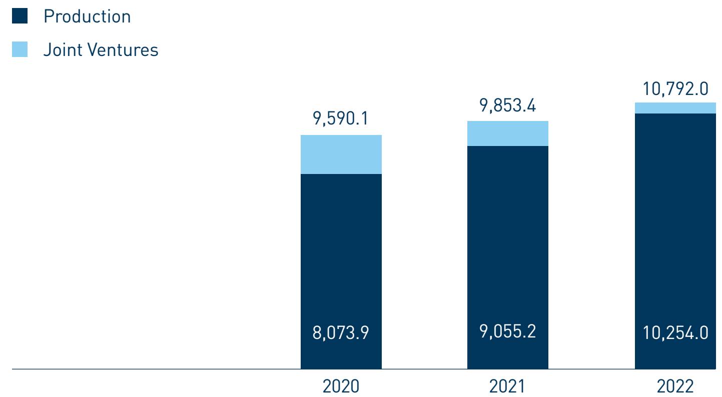
Gross Installed Capacity by Country

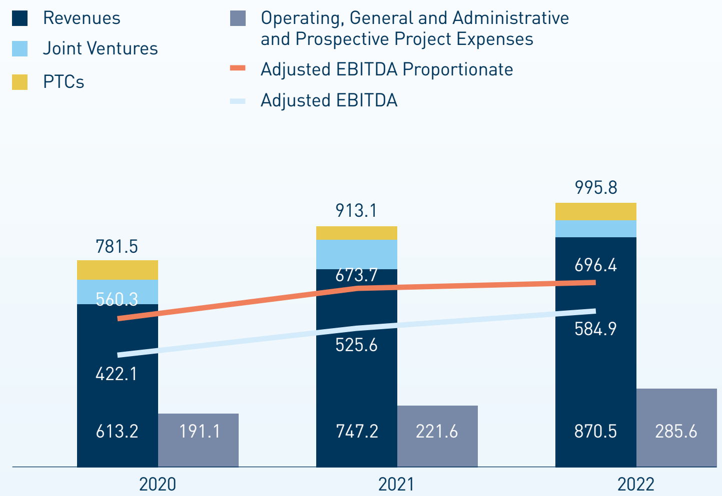


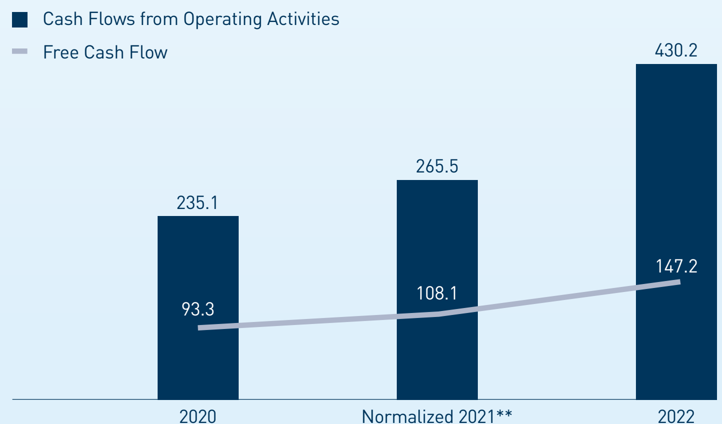
Gross Installed Capacity by Source of Energy (MW)



Financial Key Performance Indicators







**Some of the 2021 key figures were impacted by the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.

Message to Shareholders

Ready to Capitalize on the Global Energy Transition

The clean energy transition is here and will not be stopped. According to the International Energy Agency, energy demand growth is expected to be met almost entirely by renewables as they become the largest source of global electricity generation by 2025[1]. And this is just the beginning.

Governments around the world are enacting new policies to provide game-changing opportunities to drive the rapid deployment of new renewable energy projects.

In Canada, the government is now developing regulations to achieve its ambitious goal of a Net-Zero electricity supply by 2035[2], with a proposal to implement a 30% Investment Tax Credit for clean technologies including run-of-river, wind, and solar as well as battery energy storage[3]. This is likely to be a key driver for renewable energy projects in the country, as provinces are expected to see the demand for affordable electricity and a clean grid rising sharply.

In Quebec for example, utility Hydro-Québec anticipates needs for an additional 100 TWh of clean electricity supply by 2050[4]. Coming from a province relying almost entirely on non-emitting hydroelectricity, this shows us that the energy transition is no longer just about cleaning electricity grids, but about decarbonizing the entire energy system (including heating systems, transportation, and industrial processes) by using more clean electricity.

In the United States, the Inflation Reduction Act ("IRA"), which includes a US$370 billion investment[5] in clean energy and solutions, brings a degree of long-term stability and predictability to the sector that we have never seen before. Over a 10-year horizon, attractive tax credits for wind, solar and storage will render renewable energy more competitive than ever and motivate utilities to add renewables in their energy mix.

Russia's illegal invasion of Ukraine in 2022 has also triggered a global energy crisis. While prices for coal and methane hit record levels and oil prices increased significantly, Europe decided to accelerate its transition to renewable energy to ensure access to sufficient clean and affordable energy supplies. In this context, renewable energy is now becoming synonymous with energy security and independence.

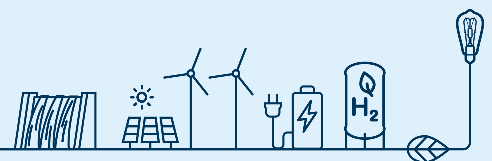
In France, the government is looking to add more renewables to its energy mix, and measures to fast-track development processes for renewable energy projects are in discussion.

In Chile, the country has set an ambitious goal of converting 70% of its total energy consumption to renewables by 2030 and pledged to become carbon neutral by 2050[6]. As a result, the share of power generation from renewable sources has reached 56% of all the energy produced in 2022, compared to 46% in 2021[7], an impressive step forward.

In light of global shifts toward Net-Zero and transparency around GHG emissions, the private sector is also driving rapid demand for renewable electricity through corporate Power Purchase Agreements ("PPAs"), while the financial community is focusing on investing in clean infrastructure.

The market outlook for renewables is larger than ever and will create abundant opportunities for renewable energy players like Innergex to meet the growing demand. We stand poised to meet these demands and look forward with great optimism.

[1] Source: https://iea.blob.core.windows.net/assets/830fe099-5530-48f2-a7c1-11f35d510983/WorldEnergyOutlook2t022.pdf
[2] Source: https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/achieving-net-zero-emissions-electricity-generation-discussion-paper.html
[3] Source: https://www.budget.canada.ca/fes-eea/2022/report-rapport/chap2-en.html#a15
[4] Source: https://www.hydroquebec.com/data/documents-donnees/pdf/plan-strategique.pdf?v=2022-03-25
[5] Source: https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf
[6] Source: https://www.weforum.org/agenda/2023/01/how-chile-is-becoming-a-leader-in-renewable-energy/
[7] Source: http://generadoras.cl/prensa/la-electricidad-y-el-impulso-renovable-como-condicion-para-el-desarrollo



Being Part of the Solution

Despite worldwide challenges in the supply chain in 2022, our team successfully advanced greenfield development and made significant strides on several projects.

In 2022, we commissioned Tonnerre, our first standalone battery facility in France. This gave us valuable insights and allowed us to fast-track our Salvador battery energy storage system, a 50 MW/250 MWh (5-hour storage) project in Chile, from development to construction in record time. Another battery energy storage system in Chile, San Andrés (35 MW/175 MWh, 5-hour storage), is also in development. We are very proud of our growing storage portfolio and the expertise we are gaining from it.

Construction at our 7.5 MW Innavik run-of-river hydro project site is also progressing well, with several milestones achieved, and a commissioning scheduled for Q3 2023. This project embodies all of our values and is a proof that our sustainable business model based on balancing the 3Ps (People, Planet and Prosperity) can create wealth and be good for the communities and the environment. This project will not only bring economic benefits to the community, it will also improve air quality by replacing the diesel, currently use to produce electricity and heat houses, by renewable energy.

In the United States, we are continuing to pursue development in many states, especially with our Boswell Springs wind project in eastern Wyoming, for which we signed a 30-year PPA for 320 MW with PacifiCorp that will deliver steady long-term returns. Other milestones reached for this project include securing the procurement of GE Renewable Energy wind turbine generators and completing the permitting process and selection of the EPC contractor. On-site construction activities will ramp up in the coming months, and upon its commissioning targeted for Q4 2024, the wind project should contribute to improving Innergex's free cash flow per share[8].

Additionally, our team is actively pursuing development and acquisition opportunities in Canada, the United States, France and Chile. In total, we currently have 8,701 MW of prospective projects in our portfolio, of which 1,093 MW are at an advanced stage.

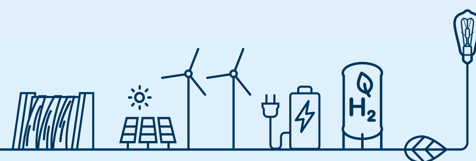
In Chile, we have become one of the largest pure-play renewable energy producers in the country with the acquisition of the San Andrés solar facility (50.6 MW) and the Aela wind portfolio (332 MW). This allowed us to complete a $1.032 billion investment-grade refinancing of the Chilean portfolio non-recourse debt, the largest private placement in Latin America in recent history.

We have also consolidated our position in France as well as in our Mountain Air portfolio of wind assets in Idaho, United States, by acquiring the remaining interests, to generate additional accretive cash flows from assets we already know and manage.

In terms of green hydrogen, we have launched the Innergex Chair located at the Université du Québec à Trois-Rivières. We hope this will help further develop the technology needed to transition green hydrogen into viable long-term energy, fuel and storage capabilities.

Thanks to our project development activities and acquisitions throughout the year, we managed to increase our revenues and adjusted EBITDA[8].

[8] These measures are not a 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.



Innergex's Competitive Edge

As renewable energy is entering a new age and production capacity is set to accelerate rapidly over the next few years, Innergex will continue to be a key player to help transition energy systems globally and create value.

To do this, Innergex will continue to rely on its best asset, its employees. With over 30 years dedicated exclusively to renewable energy, our team has accumulated the experience, knowledge, and skills to take on the new challenges the energy transition will bring.

More than ever, being a responsible corporate citizen drives our daily activities. Our Environmental, Social and Governance ("ESG") performance is a pillar of our business strategy, and we will continue to put People, our Planet and Prosperity at the centre of everything we do.

In 2022, we launched our first Climate Assessment Report aligned with the Task Force for Climate-Related Financial Disclosures ("TCFD") in an effort to release more information on the risks and opportunities our company could face. ESG is at the forefront of our business model and as we implement and pursue initiatives, we also share a desire to increase transparency on our practices.

Moreover, as a developer, builder, owner, and operator of renewable energy facilities, we have extensive knowledge of all aspects of the life cycle of a project and are more aware of our impact at every stage. This allows us to manage our assets in both a responsible and sustainable way.

As we have seen in the last few years especially, climate change will have impacts on infrastructure and availability of equipment and resources across the globe. As our team continues its efforts to build resiliency, we are already exploring mitigation solutions to optimize and maintain availability of equipment and manage production with fluctuating resource and market dynamics to maximize revenues and mitigate impacts.

Diversification across technologies and exposure to different markets is also a key element in Innergex's success. We will continue to rely on acquisitions to further diversify our portfolio and add cash accretive assets to balance cash flow streams and support project development. Our acquisition strategy brings quality additions to our existing portfolio, to achieve material synergies that will increase performance and reduce operating costs.

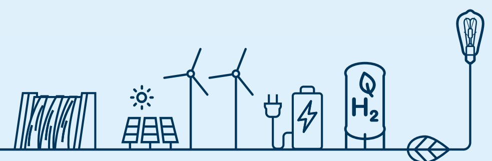
We are extremely proud of our team and all we have accomplished during this past year. Their expertise and passion for what Innergex stands for continues to inspire us every day.

And to all our stakeholders, we thank you for your unwavering support and participation to our successes.

We now turn our focus to making 2023 another successful year during which we will continue working towards achieving our Strategic Plan 2020-2025's objectives.

Daniel Lafrance
Chair of the Board

Michel Letellier
President and Chief Executive Officer



Corporate Governance

Board of Directors

The Corporation is supported by a Board of Directors which is responsible for the stewardship of the Corporation. Its mandate is to oversee the management of the business and affairs of the Corporation while taking into account ESG criteria and shareholders' interests. Members of the Board are elected at each Annual General Meeting of Shareholders where other matters are also up to a vote, including appointing the auditor of the Corporation. Each common share of the Corporation entitles its owner to one vote.

Daniel Lafrance
Chair of the Board
Independent
Joined: March 2010

Ross J. Beaty
Independent
Joined: February 2018

Pierre G. Brodeur
Independent
Joined: May 2020

Radha D. Curpen
Independent
Joined: December 2022

Nathalie Francisci
Independent
Joined: May 2017

Richard Gagnon
Independent
Joined: May 2017

Michel Letellier
Non-Independent
Joined: October 2002

Dalton McGuinty
Independent
Joined: May 2015

Monique Mercier
Independent
Joined: October 2015

Ouma Sananikone
Independent
Joined: February 2019

Louis Veci
Non-Independent
Joined: February 2020

Executive Management

Michel Letellier
President and Chief Executive Officer
Joined: 1997

Jean Trudel
Chief Financial Officer
Joined: 2002

Yves Baribeault
Chief Legal Officer and Secretary
Joined: 2009

Alexandra Boislard-Pépin
Chief Human Resources Officer
Joined: 2020

Pascale Tremblay
Chief Asset Officer
Joined: 2021

Renaud de Batz
Senior Vice President - Latin America
Joined: 2002

Patrick Beaudoin
Vice President - Asset Optimization and Procurement
Joined: 2018

Alex Couture
Vice President - Development Canada
Joined: 2022

Jacques Desrochers
Vice President - Information and Operational Technologies
Joined: 2023

Colleen Giroux-Schmidt
Vice President - Corporate Relations
Joined: 2011

Robert Guillemette
Vice President - Technical Services
Joined: 2018

Guillaume Jumel
Vice President and Managing Director - France
Joined: 2011

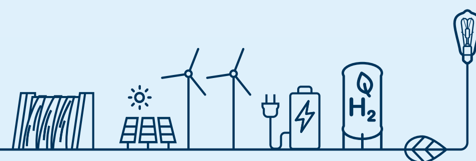
Matt Kennedy
Vice President - Environment
Joined: 2011

David Little
Vice President and Managing Director - USA
Joined: 2017

Niko Nikolaidis
Vice President - Investments and Financing
Joined: 2017

Jaime Pino
Vice President and Managing Director - Chile
Joined: 2021

Julie Turgeon
Vice President - Construction
Joined: 2023



Our ESG Commitments Reflect Our Values

PEOPLE

Achieving Together

We work together to build the better world of tomorrow. Every day, our team collaborates to make positive societal contributions while growing Innergex into a world leader in the renewable energy sector. By providing our employees with the tools they need to succeed—a safe, inclusive, and dynamic environment; a flexible work/life balance; fair and equitable compensation; generous benefits; career development opportunities; and other perks—we are able to attract and retain a skilled and diverse workforce and provide the leaders of tomorrow the chance to develop.

The physical and mental health of our employees is a key priority. Promoting safe and secure working environments is paramount to our daily operations. Our achievements are accomplished together, and so is our safety. We look out for each other, understand our responsibilities, and listen to each other's concerns. Overseen at the Senior Managmeent level by the Chief Asset Officer, our Health and Safety Management System has been structured in a Plan-Do-Check-Act format which aligns to the recommendations in ISO45001 Occupational Health and Safety Management Systems Standard. Our target is to have zero lost days due to injury and work-related fatalities.

Innergex promotes a culture where each employee – no matter what level, role or responsibility – plays an active role in creating an environment where people of diverse backgrounds feel that their voice, views, ideas, and contributions are heard and valued. Innergex has always been an equal opportunity employer that provides employees with a work environment free of discrimination and harassment.

We are proud to provide a fair, equitable, and respectful workplace where all employees are valued and given recognition based on individual merit and are considered for opportunities to advance and succeed. Our people are our advantage and we would not be where we are today without them.

Working collaboratively, learning collectively, and communicating effectively, enables us to nurture relationships and achieve our mission of building a better world with renewable energy.

In 2022

31% of women employees

73% of eligible employees participated in the Employee Share Purchase Plan

Innergex's approach to employee satisfaction

- Diversity & Inclusion policy
- Health & Safety policy
- Whistle-Blowing policy
- Workplace Environment Free of Harassment, Violence and Bullying policy
- Employee Share Purchase Plan
- Retirement plan matching contributions
- Telework policy
- Equal remuneration
- Advancing gender equality
- Career development opportunities
- Paid sick leave
- Parental leave supplemental allowance
- Employee Volunteer program
- Employee electric vehicle incentive program
- Social events
- Summer hours program
- Scholarships for employees' children

PLANET

Following Our Passion

We are driven to make a positive impact. For over 30 years, Innergex has been developing and deploying solutions to address the challenge of our time, climate change. Our renewable energy projects have been and will continue to lead in the transition to a cleaner and more equitable world for all. We remain committed to producing energy from 100% renewable sources while minimizing our footprint in our daily activities. Our environmental performance is hardwired into our objectives and the results prove that we are not only on the right path, but that everything we do matters. Building a better world with renewable energy is in our DNA.

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. Innergex is committed to ensuring that the construction and operation of facilities to harness these resources is conducted in harmony with their host environments.

In 2022, Innergex released its first Task Force on Climate-Related Financial Disclosures ("TCFD") aligned climate assessment report. This report outlines the risks and opportunities for Innergex that climate change presents to its operations. As we move forward, we expect these disclosures to mature to reflect the evolving nature of climate-related risks and opportunities and best practices. It was developed with guidance from the TCFD, our internal expertise, and an external consultant, and follows a commitment we made in 2021 to further align our disclosures with a globally recognized standard.

Our Sustainable Development Policy describes the strategies to avoid, minimize and/or mitigate the effect our facilities could have on local ecosystems. We also consider remediation and restoration as a part of this strategy for not only the land we build on, but adjacent and protected areas.

As many of our projects are located in remote areas, consideration of wildlife plays an important role in the planning, construction and operation phases of our projects. We have a successful record of partnering with government, NGOs, conservation groups, academia and local organizations to design and implement solutions to mitigate human-wildlife interaction and disturbance of important species.

In 2022

Environmental Investments of over **$2M**

Total production of **10,792 GWh** of clean electricity

Innergex's approach to environmental management

- TCFD-aligned Climate Assessment Report
- Sustainable Development policy
- Supplier Code of Conduct
- CDP Climate submissions
- SASB alignment
- UNSDGs alignment
- Climate change risk management
- GHG emission accounting
- Protecting biodiversity
- Stakeholder consultations
- Managing water resources
- Waste and hazardous waste management programs
- Compliance with laws, permits, and regulations
- Vegetation management
- Land management

PROSPERITY

Driving Opportunities

Our renewable energy projects often drive further economic and social opportunities in the communities that host them. Whether through the establishment of community development funding, partnership agreements, or our sponsorship and donation program, our impact in communities often brings tangible and long-lasting benefits. Being a responsible, transparent, and active member in the communities that host our projects is an important part of our development strategy. Sharing in the wealth we generate moves us all forward and helps build resilient and autonomous communities.

When developing long-term relationships, it is imperative that we understand and adapt to each community's individual needs and socio-economic priorities. Designed with clear expectations, our partnerships are based on open lines of communication and respect, and often act as a catalyst for sustained prosperity.

Being a good neighbour is important to Innergex and we take great pride in our track record of nurturing long-term relationships with the communities where we conduct operations. One of our Values, Get Involved, drives our commitment to be a good neighbour and a responsible corporate citizen by supporting the causes and efforts that have a broader social impact. Our sponsorships and donations have positively impacted communities and will continue to do so. More than ever, we remain committed to the values that have helped us share the benefits renewable energy facilities generate.

As the country moves ahead on its path to reconciliation with the Indigenous peoples of Canada, we continue to learn about the injustices and trauma experienced by Indigenous peoples. We believe that the private sector can play an important role in reconciliation. We are grateful to have the opportunity to draw on the knowledge and experience of our Indigenous partners as we work to that harness the power of water, sun and the wind sustainably.

When developing long-term relationships, it is imperative that we understand and adapt to each community's individual needs and socio-economic priorities. Designed with clear expectations, our partnerships are based on open lines of communication and respect, and often act as a catalyst for sustained prosperity.

In 2022

Close to

$3M shared through sponsorships, donations and voluntary contributions

31 agreements with Indigenous communities

Innergex's approach to social well-being

- Safeguard and Promotion of Human Rights policy
- Indigenous partnerships
- Sponsorship and Donation program
- Community social development funding
- Community partnerships
- Legacy project funding
- Local contracting opportunities
- Contributing to local tax base
- Royalty agreements
- Employee Matching Donation program

GOVERNANCE

Leading With Integrity

The members of our Board lead by example. Though each brings their own set of skills and experience to the table, they all share a passion for renewable energy and a focus on conducting business activities with the utmost integrity. These characteristics enable them to build and maintain trust among employees, our partners, and our shareholders by fostering open and transparent decision-making guided by our core principles and standards of behaviour.

The Board of Directors is composed of eleven members – nine independent including the Chair, and two non-independent, including the President and CEO. Board members are recruited for their experience, skills, expertise, and commitment to sustainable development. Three committees, each composed of independent members and chaired by experts in each committee's oversight provide ancillary advice and recommendations to the Board.

Our 17 policies ensure the sustainable growth of the Corporation by supporting employees with information-sharing and training, outlining our social and environmental responsibilities, maintaining transparency with shareholders and the public, and clearly laying out the Corporation's vision for ethical and acceptable behaviour.

In 2022, in response to Call to Action #92 from the Truth and Reconciliation Commission of Canada, Innergex amended its Safeguard and Promotion of Human Rights Policy to include the principles laid out in UNDRIP.

As a renewable energy producer, we are keenly aware of the importance our industry plays in people's everyday lives. Safeguarding the reliability and resiliency of the electric grid, our intellectual property, and our offtaker information is critical. Our IT department employs a comprehensive cybersecurity program guided by our IT Security Policy, which includes the industry standards, procedures, and controls to mitigate the risk of incidents and breaches. We work diligently to promote an internal culture that educates employees and promotes awareness on cybersecurity issues.

In 2022

Combined attendance at board and committee meetings

98%

36%

of Board members were women

Innergex's approach to corporate governance

- Anti-Corruption and Anti-Bribery Guidelines
- Board Diversity policy
- Code of Conduct and Ethicsline
- Information Disclosure policy
- Insider Trading policy
- Majority Vote policy
- Safeguard and Promotion of Human Rights
- Say on Pay policy
- Shareholder Engagement policy
- Whistle-Blowing policy
- Board and committee succession planning
- CEO Succession planning
- Board member recruitment and onboarding process
- Policy Regarding Minimum Shareholding by Directors and Officers
- Yearly Board training

Business Strategy

Innergex develops, acquires, owns and operates renewable power-generating facilities with a focus on hydroelectric, wind and solar production as well as energy storage technologies. The Corporation's fundamental goal is to create wealth by efficiently managing its high-quality renewable energy assets and successfully pursuing its growth.

Innergex is committed to producing energy from sustainable renewable sources exclusively and to providing energy storage capacity, guided by its 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.

Innergex owns interests in 40 hydroelectric facilities drawing on 33 watersheds, 35 wind facilities, 8 solar facilities and 1 battery energy storage facility. The expertise and innovation developed by our skilled team in various energies and different locations can be leveraged and shared across the Corporation to maximize returns from our high-quality assets.

Progressing with its Strategic Plan 2020-2025

The transition to a carbon-neutral economy will be led by the renewable energy sector. Innergex is well-positioned to continue its strategic growth and contribute to climate protection by further optimizing and growing its portfolio of renewable energy facilities. To do so, the Corporation has set four strategic goals to be achieved by 2025:

Grow Responsibly
Focus growth on current markets and target opportunities in neighbouring ones

Build Expertise
Become an expert in deploying energy storage technologies

Optimize Operations
Leverage expertise and innovation to maximize returns from its high-quality assets

Diversify Activities
Increase diversification of the Corporation's activities and assets

The Corporation will rely on its experience to pursue acquisitions and the development of new projects. It will adopt and master new technologies, mainly energy storage, expand its customer base beyond traditional utilities and deploy new business models through which it will offer more value for the electrons produced or stored.

Innergex has a solid track record, with decades of producing green energy from its quality assets. Its existing renewable energy facilities are operated by a dedicated team of skilled professionals who will continue optimizing operations and providing quality maintenance. With soaring interest in renewable energy development bringing new players to the sector, Innergex will also remain committed to the approach that has long provided responsible growth. Its belief in nurturing relationships to develop long-term partnerships with stakeholders and communities, in particular Indigenous ones, has enabled the Corporation to develop unique, value-creating renewable projects.

Portfolio of Assets

The Corporation owns interests in three groups of projects at various stages: the Operating Facilities, the Development Projects and the Prospective Projects.

As at February 22, 2023, the Corporation owns and operates 84 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1986 and July 2022, the facilities have a weighted average age of approximately 9.8 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 13.2 years (weighted average 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 mainly supported by financial or physical power hedges. In Chile, Operating Facilities sell the power generated through PPAs to power distribution companies and industrial customers, or on the open market. Please refer to the "Business Environment - Inflation" section of this MD&A for a discussion regarding inflation.

The Corporation also holds interests in projects under development that are either at an advanced development stage or under construction (the "Development Projects").

[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).

The table below outlines Operating Facilities and Development Projects as at February 22, 2023.

	Number of Facilities[1]		Gross[2] Installed Capacity (MW)		Net[3] Installed Capacity (MW)		Storage Capacity (MWh)	
	Operating Facilities	Development Projects	Operating Facilities	Development Projects	Operating Facilities	Development Projects	Operating Facilities	Development Projects
HYDRO								
Canada	33	1	1,019	8	713	4	—	—
United States	3	—	70	—	40	—	—	—
Chile	4	2	170	112	166	85	—	—
Subtotal	40	3	1,259	120	919	89	—	—
WIND								
Canada	8	—	908	—	714	—	—	—
France	16	2	324	38	324	32	—	—
United States	8	1	714	330	714	330	—	—
Chile	3	—	332	—	332	—	—	—
Subtotal	35	3	2,278	368	2,084	362	—	—
SOLAR								
Canada	1	—	27	—	27	—	—	—
United States	4	3	467	245	466	245	—	180[5]
Chile	3	—	153	—	138	—	150[4]	—
Subtotal	8	3	647	245	631	245	150	180
STORAGE								
France	1	—	—	—	—	—	9	—
Chile	—	2	—	—	—	—	—	425[6]
Subtotal	1	2	—	—	—	—	9	425
Total	84	11	4,184	733	3,634	696	159	605

[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.
[4] Capacity related to the hot water storage of the Pampa Elvira thermal solar facility.
[5] Battery storage capacity related to Hale Kuawehi (30 MW/120 MWh (4 hours)) and Paeahu (15 MW/60 MWh (4 hours)) solar projects.
[6] Salvador battery storage capacity of 50 MW/250 MWh (5 hours) and San Andrés battery storage capacity of 35MW/175 MWh (5 hours).
More information on the Corporation's Prospective Projects is available in the "Prospective Projects" section of the Management's Discussion and Analysis.

Non-Wholly Owned Subsidiaries

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

Gross installed capacity attributable to Non-wholly owned subsidiaries represents 23.2% as at February 22, 2023.

	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
Mesgi'g Ugju's'n (MU) Wind Farm L.P.	Mesgi'g Ugju's'n	150	75	Wind	Quebec	50.00%[1,2,3]
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%[1,3]
Innergex HQI USA LLC, and its subsidiaries	Curtis Mills, Palmer Falls	60	30	Hydro	New York	50.00%[3]
Innergex Sainte-Marguerite S.E.C	Sainte-Marguerite	31	15	Hydro	Quebec	50.01%
Cayoose Creek Power Limited Partmership	Walden North	16	8	Hydro	British Columbia	49.00%
Muko Partnership Holding LLC	Kokomo	6	5.4	Solar	Indiana	90.00%
Energía Coyanco S.A.	Guayacán	12	8.3	Hydro	Chile	69.47%
Pampa Elvira Solar SpA	Pampa Elvira	34	18.7	Solar	Chile	55.00%

[1] The Corporation owns more than a 50% economic interest in the entity.
[2] The Corporation owns a 50% voting interest and a participation interest of 63.7% in 2021 (participation interest to decline over the years).
[3] Based on the terms of agreements under which these entities were established, the Corporation is exposed to, and has right to, variable returns from its involvement with the investee, and has the current ability to direct these entities's activities that most significantly affect the returns.

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.

Gross installed capacity attributable to Non-wholly owned subsidiaries represents 11.7% as at February 22, 2023.

	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
Toba Montrose General Partnership	East Toba and Montrose Creek	235	94	Hydro	British Columbia	40.00%[1,2]
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]
Parc éolien communautaire Viger-Denonville, S.E.C.	Viger-Denonville	25	12	Wind	Quebec	50.00%
Umbata Falls L.P.	Umbata Falls	23	11	Hydro	Ontario	49.00%

[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 control over the decision-making process.

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, 2022, and reflects all material events up to February 22, 2023, 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 year ended December 31, 2022.

The audited consolidated financial statements attached to this MD&A and the accompanying notes for year ended December 31, 2022, along with the 2021 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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1- HIGHLIGHTS | Financial Year 2022 – Growth Initiatives

On January, 28, 2022, Innergex completed the acquisition of the 50.6 MW San Andrés solar farm in Chile (the "San Andrés Acquisition"). The facility, commissioned in 2014, is located in the Atacama Desert in northern Chile. San Andrés was acquired for a total consideration of US$26.8 million ($34.1 million). The facility is expected to produce a gross long-term average of approximately 118.9 GWh per year.

On February 10, 2022, Innergex entered into foreign exchange forward contracts with an aggregate notional amount of US$100.0 million ($124.9 million) to manage its exposure to exchange rate fluctuations related to the purchase price of the acquisition of Aela Generación S.A. and Aela Energía SpA (together "Aela"). In addition, in order to manage its exposure to the risk of increasing interest rates on a portion of the expected refinancing of the Aela Acquisition and the existing Chilean projects, Innergex entered into forward start interest rate swaps between February 17 and March 1, 2022, with an aggregate notional amount of US$331.2 million ($413.9 million). Furthermore, to mitigate the interest rate risk related to the Alterra term loan, Innergex entered into interest rate swaps between February 24 and February 28, 2022, with an aggregate notional amount of $145.0 million.

On April 29, 2022, to take advantage of the currently favourable energy pricing environment in France, Innergex entered into three power purchase agreements for its Antoigné, Porcien and Vallottes wind facilities (the "New PPAs"), in effect since August 1, 2022, concurrently with the cancellation of the current power purchase agreements. In addition, the New PPAs effectively increase the contracted period of the facilities to December 31, 2025.

On May 10, 2022, the Corporation amended its existing revolving term credit facility, extending the term from 2023 to 2027 and increasing the borrowing limit to $950.0 million.

On May 10, 2022, Innergex announced that it has awarded Mitsubishi Power an order for two utility-scale battery energy storage systems ("BESS") in Chile. These projects will be colocated with solar energy and enable peak shifting by storing excess solar energy during the day and dispatching at night. Innergex's 68 MW Salvador solar photovoltaic facility will add 50 MW/250 MWh (5 hours) of energy storage, and its 50.6 MW San Andrés solar photovoltaic facility will add 35 MW/175 MWh (5 hours) of energy storage.

On May 18, 2022, Innergex received approval from the TSX to proceed with a normal course issuer bid on its common shares, Series A Preferred Shares, and Series C Preferred Shares.

On June 9, 2022, Innergex completed its previously announced acquisition of all of the ordinary shares of Aela (the "Aela Acquisition"), a 332 MW portfolio of three newly-built operating wind assets in Chile, for a cash consideration of US$324.3 million ($408.2 million), and the assumption of the existing non-recourse debt.

On July 22, 2022, the Corporation announced the full commissioning of the 9 MW/9 MWh (1 hour) Tonnerre battery energy storage system in France. Tonnerre has been awarded a 7-year contract for differences offering a fixed-price contract for capacity certificate. The facility will generate additional revenues that will vary based on prevailing energy pricing. The facility will provide grid stability and help balance and secure the French power transmission system.

On July 25, 2022, to take advantage of the currently favourable energy pricing environment in France, Innergex notified the counterpart to the Longueval wind project's power purchase agreement of its intention to cancel the agreement. The project will sell its electricity on a merchant price basis. The cancellation came into effect on November 1, 2022.

As part of Innergex's refinancing of the non-recourse debt of its Chilean facilities, the interest rate swaps, previously entered into to mitigate the risk of interest rate fluctuations during the negotiation process, were settled on July 25, 2022 in favour of Innergex, for US$ 41.2 million ($53.1 million).

On August 5, 2022, the Corporation announced the successful completion of a US$803.1 million ($1.032 billion) refinancing of the non-recourse debt of its portfolio of wholly owned assets in Chile with the issuance of US$710.0 million ($912.6 million) green bonds maturing in 2036 (with a balloon payment of US$139.0 million ($178.7 million)) and a US$93.1 million ($119.7 million) letter of credit facility. The refinanced portfolio is composed of a combination of solar, wind and hydro assets as well as battery energy storage systems ("BESS'') assets wholly owned by Innergex. Overall, the Chilean portfolio of assets received an investment grade rating, and the green bonds were priced at competitive levels over United States Treasuries ("UST").

On August 16, 2022, the Corporation signed a 30-year, 320 MW PPA with PacifiCorp, a Berkshire Hathaway subsidiary, for the electricity to be produced by the Boswell Springs wind project located in eastern Wyoming. The commercial operation date is scheduled during Q4 2024.

On October 4, 2022, the Corporation successfully completed the previously announced acquisition of the remaining 30.45% minority interest in its wind portfolio of 16 assets in France (the "French Acquisition") for a total consideration of $96.4 million.

On October 5, 2022, concurrent with the closing of the French Acquisition, Innergex monetized its Euro/CAD foreign exchange forward contracts for a total gain of $43.5 million and simultaneously amended the Euro/CAD foreign exchange forward contracts for a total notional amount of $115.3 million amortizing until 2043 and allowing conversion at a fixed rate of CAD 1.4838/Euro.

On October 10, 2022, to take advantage of the currently favourable energy pricing environment in France, Innergex entered into two power purchase agreements for its Bois d'Anchat and Beaumont wind facilities (the “New PPAs”), which took effect on January 1, 2023, concurrently with the early termination of the current power purchase agreements. In addition, the New PPAs effectively increase the contracted period of the facilities to December 31, 2032.

On December 14, 2022, the Corporation acquired all the Class A shares of its 138 MW Mountain Air wind portfolio in Idaho, United States (the "Mountain Air Acquisition"), for a total consideration of US$47.5 million ($64.4 million) from its tax equity partner. These shares represent the remaining 37.75% of the outstanding shares of the portfolio not already owned by Innergex.

During 2022, the Corporation added 5 net new Prospective Projects for a total of 188 MW. Its portfolio now aggregates 79 projects for a total of 8,701 MW, with 15 projects currently at an advanced stage, for a total 1,093 MW of installed capacity.

1- HIGHLIGHTS | Financial Year 2022 – Selected Information

	Year ended December 31				
	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized	2020
OPERATING RESULTS					
Production (MWh)	10,254,005	9,055,215	—	9,055,215	8,073,914
Revenues	870,494	747,208	(54,967)	692,241	613,207
Operating, general, administrative and prospective projects expenses	285,579	221,571	—	221,571	191,098
Adjusted EBITDA[1]	584,915	525,637	(54,967)	470,670	422,109
Net (Loss) Earnings	(91,115)	(185,394)	64,219	(121,175)	(29,111)
Adjusted Net (Loss) Earnings[1]	(34,860)	(6,951)	—	(6,951)	22,311
PROPORTIONATE					
Production Proportionate (MWh)[1]	10,792,047	9,853,366	—	9,853,366	9,590,140
Revenues Proportionate[1]	995,758	913,147	(95,273)	817,874	781,466
Adjusted EBITDA Proportionate[1]	696,362	673,745	(95,273)	578,472	560,328
COMMON SHARES					
Dividends declared on Common Shares	146,957	132,229	—	132,229	125,543
Dividends declared on Series A Preferred Shares	2,757	2,757	—	2,757	3,067
Dividends declared on Series C Preferred Shares	2,875	2,875	—	2,875	2,875
Weighted Average Number of Common Shares (in 000s)	201,836	180,857	—	180,857	170,292

	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized	2020
CASH FLOW AND PAYOUT RATIO					
Cash Flow From Operating Activities[2]	430,243	265,498	17,093	282,591	235,108
Free Cash Flow[1,2]	147,248	92,315	15,789	108,104	93,260
Payout Ratio[1,2]	100 %	143 %	(21)%	122 %	135 %
Adjusted Payout Ratio[1,2]	85 %	98 %	— %	98 %	114 %

	As at December 31		
FINANCIAL POSITION	2022	2021	2020
Total Assets	8,602,427	7,396,068	7,141,598
Total Liabilities	7,116,000	6,035,388	6,070,666
Equity Attributable to Owners	1,316,195	1,093,112	1,008,854
Non-Controlling Interests	170,232	267,568	62,078

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators 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.
2. For more information on the calculation and explanation, please refer to the "Free Cash Flow and Payout Ratio" section.
3. For the year ended December 31, 2021, the operating results, the Cash Flow From Operating Activities, Free Cash Flow and Payout Ratio are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

1- HIGHLIGHTS | Financial Year 2022 – Operating Performance

For the year ended December 31, 2022, **Revenues** were up 26% to $870.5 million compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events. The **hydroelectric** power generation segment recorded an increase in revenues mainly attributable to the acquisitions of Curtis Palmer on October 25, 2021, of the remaining 50% interest in Energía Llaima on July 9, 2021, for which results are now included in Innergex's consolidated revenues, and of Licán on August 3, 2021. The increase is also explained by the BC Hydro Curtailment Payment mitigated by exceptionally low production at the facilities in British Columbia due to drier weather. The increase in revenues in the **wind** power generation segment compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events, is mainly due to the acquisition of the Aela wind farms on June 9, 2022, the commissioning of the Griffin Trail facility on July 26, 2021, and to higher production from the facilities in Quebec. The increase in revenues from the **solar** power generation segment compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events, was mostly due to the higher selling prices at the Phoebe facility, the San Andrés Acquisition on January 28, 2022, and to the contribution of the Pampa Elvira facility following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021. Revenues Proportionate[1] were up 22% at $995.8 million compared with the same period last year, for which Revenues Proportionate[1] were normalized to exclude the February 2021 Texas Events.

For the year ended December 31, 2022, **Operating, general, administrative and prospective projects expenses** were up 29% to $285.6 million compared with the same period last year. The **hydroelectric** power generation segment recorded an increase in expenses due to higher maintenance costs at some facilities in British Columbia following the floods that occurred at the end of 2021, higher expenses following the acquisitions of Curtis Palmer, the remaining 50% interest in Energía Llaima and of Licán. In the **wind** power generation segment, these expenses increased due mainly to the acquisition of the Aela wind farms, the commissioning of the Griffin Trail facility and the impact of the 2022 Supplementary Budget Act in France. The increase in the **solar** power generation segment is explained by higher operating expenses following the commissioning of the Amazon Solar Farm Ohio - Hillcrest ("Hillcrest") facility, and the acquisition of the San Andrés and Pampa Elvira facilities.

As a result of the factors explained above, the Adjusted EBITDA[1] was 24% higher at $584.9 million for the year ended December 31, 2022 and the Adjusted EBITDA Proportionate[1] was 20.4% higher at $696.4 million, compared with the same period last year, for which the Adjusted EBITDA[1] and the Adjusted EBITDA Proportionate[1] were normalized to exclude the February 2021 Texas Events.

Innergex recorded a net loss of $91.1 million ($0.43 net loss per share - basic and diluted) for the year ended December 31, 2022, compared with a net loss of $185.4 million ($1.09 net loss per share - basic and diluted) for the corresponding period in 2021. In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, the decrease in net loss is explained by the impacts of the February 2021 Texas Events in 2021, and by the impairment charges in the Flat Top and Shannon joint ventures recognized during the same year. These items were partly offset by an $80.4 million increase in depreciation and amortization and a $65.6 million increase in finance costs, mainly attributable to the recent acquisitions and commissionings, and a $10.9 million increase in impairment of long-term assets following the impairment charges recognized in 2022 on the Hawaiian projects and on the safe harbor solar modules, partly offset by the impairment charges recognized in 2021.

[1] These measures 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.

1- HIGHLIGHTS | Financial Year 2022 – Capital and Resources

The increase in total assets results largely from the assets acquired following the San Andrés and Aela acquisitions and the start of the Hale Kuawehi, Boswell Springs and Salvador and San Andrés battery storage construction activities. These items were partly offset by depreciation and amortization and by an upward shift in interest rate curves, which contributed to the decrease of the asset retirement obligation included in property, plant and equipment.

The increase in total liabilities results largely from the increase in the long-term loans and borrowings stemming from the long-term loans and borrowings assumed in the Aela Acquisition and from net draws on the revolving term credit facility, used toward the Aela Acquisition and the construction and development activities and from the increase in deferred taxes, mainly related to the Aela Acquisition and the change in fair value of hedging instruments. These items were partly offset by the decrease in derivative financial instruments' fair values.

The increase in equity attributable to owners results largely from the shares issued related to the public offering in February 2022 and the concurrent Hydro-Québec private placement, and the total comprehensive income, partly offset by the dividends declared on common and preferred shares and the distributions to non-controlling interests.

The increase in cash flows from operating activities before changes in non-cash operating working capital items for the three months ended December 31, 2022, is mainly due to the realized gain on financial instruments following the settlement of the foreign exchange forward contracts concurrent with the French Acquisition, partly offset by an increase in finance costs paid mainly related to the Aela and San Andrés acquisitions. For the year ended December 31, 2022, Free Cash Flow[1] was impacted by the above, partly offset by a decrease in cash flows from operating activities before changes in non-cash operating working capital items from the Phoebe facility, due mostly to an unfavourable difference between sales at the Phoebe node and purchases at the ERCOT South hub.

1- HIGHLIGHTS | Subsequent Events

Acquisition of Sault Ste. Marie Solar Portfolio

On January 23, 2023, the Corporation announced that it has entered into an agreement to acquire the 60 MW Sault Ste. Marie solar portfolio located in northwestern Ontario for a purchase price of $50.2 million, along with the assumption of $169.5 million of existing debt. The portfolio is composed of the Sault Ste. Marie 1 (20 MW), Sault Ste. Marie 2 (30 MW) and Sault Ste. Marie 3 (10 MW) solar facilities. The acquisition is expected to close in Q1 2023 and is subject to certain regulatory approvals in Canada, key third party consents and other customary closing conditions.

Refinancing of the subordinated unsecured term loan

On February 1, 2023, Innergex has completed the refinancing of the subordinated unsecured term loan with a non-revolving term credit facility of $75.0 million bearing interest at a fixed rate of 6.25% and maturing on February 1, 2025, and a non-revolving term credit facility of $75.0 million bearing interest at a variable rate of 4.87%, based on the bankers' acceptance rates plus a spread of 1.85% which depends on leverage ratio, maturing on February 1, 2025. Concurrently, the Corporation concluded an interest rate swap to hedge a $50.0 million portion of the credit facility notional that is subject to variable interest rates.

1- HIGHLIGHTS | Financial Year 2021

For the year ended December 31, 2021, the increase in Production (MWh), Revenues, Operating, general and administrative expenses, Adjusted EBITDA[1] and Adjusted EBITDA Proportionate[1] were attributable mostly to the acquisition of the remaining 50% interest in Energía Llaima, which is now included in Innergex's consolidated revenues, the Curtis Palmer Acquisition, the first full year of contribution from the Mountain Air 2020 acquisition and the commissioning of the Griffin Trail wind facility.

The increase in loss from continuing operations in 2021 is mainly due to a net unfavourable impact from the February 2021 Texas events, the recognition of impairment charges in the Flat Top and Shannon joint ventures and in the Phoebe solar facility in Texas, the increase in depreciation and amortization from the facilities commissioned in 2020 and the acquisitions in 2021,

[1] These measures 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.

an unfavourable change in the fair value of financial instrument and an increase in finance costs. These items were partly offset by an increase in recovery of income tax mainly related to the impacts of the February 2021 Texas Events and the reversal of deferred tax liabilities related to the Flat Top and Shannon joint venture facilities and an increase in the tax attributes and PTCs allocated to the tax equity investors.

The increase in total assets results largely from the Energía Llaima, Licán and Curtis Palmer acquisitions and the construction activities of the Hillcrest solar and Griffin Trail wind facilities, partly offset by an impairment charge recognized in the Phoebe solar facility and the decrease in investments in joint ventures, mainly explained by the February 2021 Texas Events, the impairment loss at the Shannon and Flat Top facilities and the acquisition of the remaining 50% interest in Energía Llaima.

The increase in long-term loans and borrowings results largely from the debt assumed in the Energía Llaima and Licán acquisitions, the net draws made toward the construction of the Hillcrest and Griffin Trail facilities and the purchase price of Curtis Palmer, partly offset by the proceeds received from the public offering of common shares and the Hydro-Québec private placements applied against the revolving credit facility.

The increase in equity attributable to owners is mainly attributable to shares issued related to the Energía Llaima Acquisition, the public offering and the concurrent Hydro-Québec private placements and the investment made by HQI US Holding LLC, a subsidiary of Hydro-Québec, in the Curtis Palmer Acquisition, partly offset by the total comprehensive loss attributable to owners of the parent and dividends declared.

Cash flows from operating activities before changes in non-cash operating working capital items increased, mainly due to the Energía Llaima, Licán and Curtis Palmer acquisitions, to the facilities commissioned in 2021, and to the full-year impact of the Salvador and Mountain Air acquisitions of 2020. Free Cash Flow was favourably impacted by the above, partly offset by an increase in debt principal repayments and an increase in Free Cash Flow[1] attributed to non-controlling interests, stemming mainly from the Curtis Palmer Acquisition and the full-year impact of the Mountain Air 2020 acquisition.

2- OVERVIEW OF OPERATIONS | Business Environment

Key Growth Factors

Innergex'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;
- stable and long-term government policies for climate change mitigation and adaptation and 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 regional electricity markets;
- sustainable merchant prices in the different 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 and to provide firm power with the increasing market readiness and cost effectiveness of storage technologies.

Key Geographic Markets

In **Canada**, growth opportunities for new renewable power generation have resulted from commitments to reduce greenhouse gas (GHG) emissions; the national price on carbon pollution; public concern over fossil fuel power generation, air quality and GHGs; and improvements in renewable energy technology and affordability. Renewable electricity generation in Canada is also supported by federal and provincial procurements that result in long-term fixed price contracts with crown corporations, incentives such as accelerated depreciation, and legislated commitments to renewable energy generation. The announced investment tax credit for clean technologies is expected to continue to make renewable resources the most competitive option for new electricity generation. The Government of Canada has committed to reduce GHG emissions by 40-45% from 2005 levels by 2030 and achieve net-zero emissions economy-wide by 2050. Federal clean growth and climate plans prioritise expanding renewable electricity generation and its enabling infrastructure. Specific commitments in the electricity sector include phasing out coal-fired electricity generation by 2030 and achieving a net-zero electricity grid by 2035. Canada's electricity grid is currently 82% emissions-free. Nationally, the largest source of power is hydroelectricity, with an installed capacity of over 80 GW representing around 60% of annual power generation. Wind and solar power met approximately 6.3% of Canada's electricity demand in 2021 and continue to account for the largest share of new power generation additions annually. It is anticipated that the phase-out of fossil fuel-fired electricity generation and increasing electrification across the economy will lead to a significant increase in demand for renewable electricity, with multiple reports estimating that Canada will require two to three times its current non-emitting generating capacity by 2050.

In the **United State**s, electricity is sold under various types of contracts, including long-term PPAs, power hedges, and commercial and retail contracts. Favourable costs for renewable electricity generation, combined with legislated commitments toward GHG emissions reductions and renewable electricity generation at the federal and state levels, are expected to continue driving demand for new renewable generation capacity. The 2022 enactment of the Inflation Reduction Act directed nearly $400 billion in federal funding to clean energy in the form of tax credits designed to catalyze private investment in clean energy. The U.S. Government aims to achieve a 50-52% reduction in economy-wide GHG emissions from 2005 levels by 2030 and reach net-zero by 2050. It has established a goal to reach 100% carbon pollution-free electricity generation by 2035. States continue to be active in adopting and increasing renewable portfolio standards (RPS) policies that require electricity suppliers to source a certain amount of their electricity from eligible technologies. As of November 2022, 36 states and the District of Columbia have established an RPS or a renewable energy goal. In 12 of those states (and the District of Columbia), the requirement is for 100% clean electricity by 2050 or earlier. Electricity generation in the U.S. is approximately 61% from fossil fuels, 19% from nuclear energy, and 20% from renewable energy sources. Wind is the largest renewable source of generation (9.2%), followed by hydropower (6%) and solar (2.8%). The share of renewables in electricity generation is expected to more than double to 44% by 2050, surpassing methane as the leading source of power.

France is currently facing an energy crisis due to high methane prices and low nuclear availability, which drove energy prices to record levels. This crisis has increased the demand for corporate PPAs, which could lead to more direct contracting opportunities for new-build assets as well as contract renewal for older assets. Recent measures taken by the government introduced a special contribution from renewable producers equal to 90% of all revenues generated when the price of energy sold is above 100€/MWh. A new law (Loi sur l'Accélération des Énergies Renouvelables) that would change the regulatory framework is also set to be passed in early 2023. This law is expected to foster renewable development in the country by reducing the permitting timeline and accelerating the interconnection process. France will also announce later in 2023 its long-term energy strategic plan (Programmation Pluriannuelle de l'Énergie or "PPE"). The French PPE is updated every 3 or 4 years. The 2023 version is expected to favour solar, offshore wind and nuclear power. Based on recent announcements by the French government, it is believed that the target for solar power capacity will be raised to 100 GW by 2050 and the target of 35 GW for onshore wind will be postponed to 2050 (compared to 2035 previously). The French electricity system is largely deregulated for production, ancillary services and electricity supply. It is, however, still a monopoly for distribution and transmission. The transmission system operator (RTE) and the distribution operator (ENEDIS), both subsidiaries of Électricité de France (EDF), are responsible for managing distribution and transport infrastructure and have a duty to provide interconnection to renewable energy projects at standardized conditions. As such, the energy environment remains very favourable to renewable developers. 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 100 GW of solar and 35 GW of offshore wind, RFPs are expected to call for 1.5 to 2 GW of additional wind projects every year and close to 2 GW of additional solar 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 2022, the production of solar and wind energy reached a total of 23,062 GWh, a 28.2% increase from 2021, and representing 27.7% of the total generated power. Meanwhile, hydroelectric facilities accounts for 24% of the total generation (20,290 GWh). As of December 2022, there were 66 renewable energy facilities under construction, representing 3,532 MW of capacity. Non-conventional renewable energies, which do not include hydropower with reservoirs, now make up 41% of the country's installed capacity, 33,218 MW, and contribute 28% of annual electricity generation. Mining, which consumes about a third of Chile's overall power production, is also an 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 consumption expenses. In Latin America, demand for electricity remains strong and governments are seeking to increase the production of renewable energy, of which there is an ample resource. Chile has set legislated commitments to renewable energy, which target increases in renewable energy generation to 60% by 2035 and 70% by 2050. Its target under the Paris Agreement is to peak annual GHG emissions by 2025 and reduce them to 95 Megatonnes by 2030. One of the most concrete actions to date has been the Retirement Plan and/or Reconversion of Units to Coal, which aims to decommission remaining coal-fired power plants (which still provide 23% of Chile's electricity) by 2040. Several coal-fired units have already closed and the goal could be reached sooner, possibly in 2030 or 2025. The National Electric Coordinator acts as the independent system operator for the National Electric System in Chile. It is charged with coordinating electricity generation throughout the system to achieve operational and cost efficiency, while transmission and distribution costs are regulated by law. It also preserves the security of electrical service and must guarantee open access to the transmission system according to law. In 2013, only 5% of the electricity production in Chile was generated from non-conventional renewable sources. In 2021, non-conventional renewable generation reached 28% of the total generation, surpassing a 2013 law that mandated that 20% of the electricity produced in Chile come from renewable energy by 2025 and now there is a draft law that increases to 40% by 2030. The solar and wind energy sectors are the most popular sectors since Chile is geographically well positioned. The solar irradiation in the Atacama Desert and the winds from the Pacific coast and the Andes Mountains make Chile a promising market for renewable energy production.

Seasonality of Operations

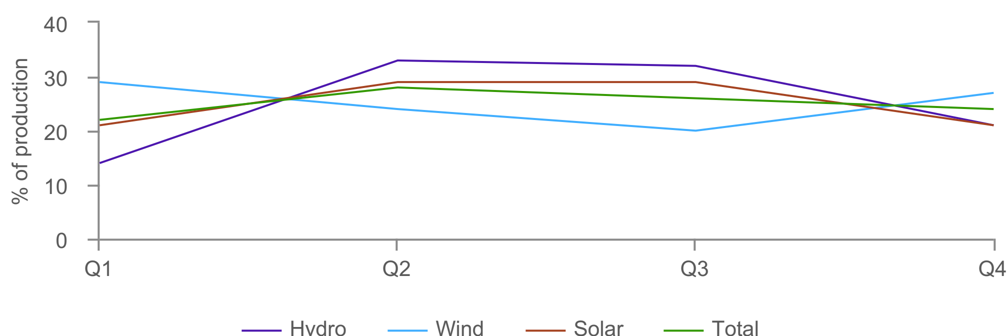
The Corporation aims to maintain a diversified portfolio of assets in terms of geography and sources of energy to alleviate any seasonal and production variations. The amount of electricity generated by the Operating Facilities is generally dependent on the availability of water flows, wind regimes and solar irradiation. Lower-than-expected resources in any given quarter 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	539	14 %	1,257	33 %	1,219	32 %	825	21 %	3,840	32 %
WIND	1,787	28 %	1,564	24 %	1,352	21 %	1,762	27 %	6,465	55 %
SOLAR	330	21 %	443	29 %	449	29 %	316	21 %	1,538	13 %
Total	2,656	22 %	3,264	28 %	3,020	26 %	2,903	24 %	11,843	100 %

1. The consolidated long-term average production is the annualized LTA for the facilities in operation as of February 22, 2023. 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 Figures" section.

Seasonality of Production by Energy Source



Inflation

In the wake of the global pandemic and the current geopolitical context, the geographic segments in which Innergex operates have been impacted by rising inflation pressure as a result of increased consumer spending, labour shortages and worldwide supply chain disruptions. The Corporation's operating facilities have shown resiliency toward inflation as most of its long-term PPAs contain partial or full indexation clauses that annually adjust for the effects of inflation. This also applies to Innergex's development and construction projects, except for certain projects for which PPA repricing discussions are presently taking place (please refer to the "Construction Activities" and "Development Activities" sections of this MD&A for more information). As such, inflation pressures on the Corporation's operating, general and administrative expenses and construction costs are generally absorbed by higher revenues.

Global Climate Change

Climate change, which increases the likelihood, frequency and severity of adverse weather conditions such as severe storms, droughts and water stress, heat waves, forest fires, rising temperatures and changing precipitation patterns, presents both risks and opportunities to the Corporation. Climate change has proven to disrupt weather patterns in ways that are difficult to anticipate, which could result in more frequent and severe disruptions to the Corporation’s generation facilities and the power markets in which the Corporation operates. In addition, energy demands generally vary with weather conditions.

The Corporation’s facilities and projects are exposed to various hazards that are expected to increase in the future under various climate scenarios. 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. When planning for capital investments or asset acquisitions, the Corporation considers site-specific climate and weather factors, such as flood plain mapping and extreme weather history. 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. Despite all the measures in place to prepare for and respond to extreme weather events, there is no assurance that there would be no consequences on the Corporation’s revenues and profitability.

This year, the Corporation released its first Task Force on Climate-related Financial Disclosures (“TCFD”) aligned climate assessment report, an important step in its sustainability journey and essential in identifying and addressing the climate risks and opportunities for Innergex. It was developed with guidance from the TCFD, internal expertise, and an external consultant, and follows a commitment made in 2021 to further align disclosures with a globally recognized standard.

Through consultations with various levels of the Corporation, including the Board of Directors, the executives as well as experts in each of the jurisdictions in which the Corporation operates, the team gained an understanding of the resilience of the business in different potential climate futures by performing assessments, on a facility-by-facility basis, of their potential physical and transition impacts. The bulk of this work included a deep dive of the business through climate-related scenario analysis to inform business strategy and financial planning processes and assess the resilience of its strategies against various climate-related scenarios. The report is available on sustainability.innergex.com.

2- OVERVIEW OF OPERATIONS | Operating Facilities

Energy segment	Location	Three months ended December 31, 2022		Three months ended December 31, 2021		Three months Production % change	Year ended December 31, 2022		Year ended December 31, 2021		Twelve months Production % change
		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA	
HYDRO	Quebec	181,379	100 %	170,605	94 %	6 %	716,024	102 %	688,416	98 %	4 %
	Ontario	17,159	81 %	25,643	121 %	(33)%	68,799	92 %	75,105	101 %	(8)%
	British Columbia	167,871	45 %	552,153	148 %	(70)%	1,767,031	80 %	2,152,452	98 %	(18)%
	United States[3]	68,514	75 %	89,664	123 %	(24)%	332,113	88 %	125,012	109 %	166 %
	Chile[4]	144,528	92 %	105,232	67 %	37 %	447,085	91 %	215,843	70 %	107 %
	Subtotal	**579,451**	**70 %**	**943,297**	**117 %**	**(39)%**	**3,331,052**	**87 %**	**3,256,828**	**96 %**	**2 %**
WIND	Quebec	623,375	94 %	586,484	89 %	6 %	2,284,974	99 %	2,124,480	92 %	8 %
	France	207,039	95 %	173,486	80 %	19 %	659,974	88 %	646,208	86 %	2 %
	United States	557,028	89 %	644,724	103 %	(14)%	2,270,446	93 %	1,938,737	99 %	17 %
	Chile[6]	142,758	56 %	—	— %	— %	419,996	72 %	—	— %	— %
	Subtotal	**1,530,200**	**87 %**	**1,404,694**	**93 %**	**9 %**	**5,635,390**	**92 %**	**4,709,425**	**94 %**	**20 %**
SOLAR	Ontario	6,757	123 %	5,758	104 %	17 %	39,080	108 %	38,994	107 %	— %
	United States	164,757	83 %	162,408	84 %	1 %	980,356	86 %	853,798	84 %	15 %
	Chile[4,5]	75,874	70 %	67,000	94 %	13 %	268,127	79 %	196,170	94 %	37 %
	Subtotal	**247,388**	**79 %**	**235,166**	**87 %**	**5 %**	**1,287,563**	**85 %**	**1,088,962**	**87 %**	**18 %**
TOTAL PRODUCTION[1]		**2,357,039**	**81 %**	**2,583,157**	**100 %**	**(9)%**	**10,254,005**	**90 %**	**9,055,215**	**94 %**	**13 %**
Innergex's share of production of joint venture and associates		91,587	105 %	93,000	106 %	(2)%	538,042	100 %	798,151	97 %	(33)%
PRODUCTION PROPORTIONATE[1,2]		**2,448,626**	**82 %**	**2,676,157**	**100 %**	**(9)%**	**10,792,047**	**90 %**	**9,853,366**	**94 %**	**10 %**

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 production and included in production proportionate.
2. The results from the Flat Top and Shannon joint venture facilities from April 1, 2021, onward were excluded due to the projects' assets and liabilities being classified as disposal groups held for sale, until their sale on December 28, 2021, and March 4, 2022, respectively.
3. The Curtis Palmer Acquisition was completed on October 25, 2021.
4. The acquisition of the remaining 50% interest in Energía Llaima was completed on July 9, 2021, and the Licán Acquisition was completed on August 3, 2021.
5. The San Andrés Acquisition was completed on January 28, 2022.
6. The Aela Acquisition was completed on June 9, 2022.

Production for the three-month period ended December 31, 2022, was 81% of LTA. The result is mostly explained by exceptionally low water flows at the facilities in British Columbia and at Curtis Palmer due to drier weather, mechanical issues at the Foard City wind facility, lower irradiation and economic curtailment at the Phoebe facility in Texas and in Chile combined with below-average wind regimes in Quebec and France. These items were partly offset by higher production from the Quebec hydro facilities. Innergex's share of production of joint ventures and associates was 105% of LTA, translating into a Production Proportionate at 82% of LTA.

Production for the year ended December 31, 2022, was 90% of LTA. The result is mostly explained by lower production at the facilities in British Columbia due to cooler weather delaying the freshet followed by drier weather, lower irradiation and economic curtailment at the Phoebe facility in Texas and in Chile and below-average wind regimes in France and mechanical issues at the Foard City facility in Texas. These items were partly offset by above-average wind regimes at the Griffin Trail facility in Texas and the Quebec facilities. Excluding Phoebe's economic curtailment, production for the US solar segment would have reached 95% of LTA. Innergex's share of production of joint ventures and associates was 100% of LTA, translating into a Production Proportionate at 90% of LTA.

2- OVERVIEW OF OPERATIONS | Commissioning Activities

On July 22, 2022, Innergex completed the full commissioning of the 9 MW/9 MWh (1 hour) Tonnerre battery energy storage system in France. Tonnerre has been awarded a 7-year contract for differences offering a fixed-price contract for capacity certificate. The facility will generate additional revenues that will vary based on prevailing energy pricing.

2- OVERVIEW OF OPERATIONS | Construction Activities

The table below outlines the projects that are under construction as at the date of this MD&A.

Name (Location)	Type	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Expected COD
Hale Kuawehi (Hawaii, U.S.)	Solar	100	30.0 [2]	87.4 [3]	25	2024
Innavik (QC, Canada)	Hydro	50	7.5	54.7	40	2023
Boswell Springs (Wyoming, U.S.)	Wind	100	329.8	1,262.0	30	2024
Salvador Battery Storage (Chile)	Storage	100	Note [4]	0.0	0	2023
San Andrés Battery Storage (Chile)	Storage	100	Note [5]	0.0	0	2023

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. Solar project with a battery storage capacity of 30 MW/120 MWh (4 hours).
3. PPA is a fixed lump sum capacity payment for the availability of dispatchable energy.
4. Battery storage capacity of 50 MW/250 MWh (5 hours).
5. Battery storage capacity of 35 MW/175 MWh (5 hours).

Updated status for the following projects:

Hale Kuawehi:

- Major construction is still suspended until PPA repricing is agreed upon.
- Tesla BESS supply amendment executed, guaranteeing all components delivered by Q4 2023.
- An amendment to the PPA was executed with HECO and will be submitted to the Public Utility Commission (PUC) for consideration of approval.
- Project COD expected in Q3 2024.

Innavik:

- Construction of the civil structures is almost completed, with the only remaining item to be completed being to close the derivation structure in order to raise the water level in the upstream headpond.
- The installation of the stoplogs in the derivation was postponed to Q2 2023 due to cold weather.
- Installation of the electromechanical equipment is almost completed and is ready for dry commissioning.
- The contractor has registered a legal hypothec in Q1 2023 claiming for payment of additional costs. The Corporation intends to dispute that claim.
- Project COD to be postponed to Q3 2023.

Boswell Springs

- PPA approval from Wyoming PUC was obtained and PPA with PacifiCorp is effective since January 2023.
- Engineering, Procurement and Construction Agreement nearing finalization and to be signed in Q1 2023.
- Financial close is planned for Q1 2023.
- Project COD expected in Q4 2024.

Salvador Battery Storage

- Earth works, precast foundations installation and the substation extension are completed.
- Electrical works, interconnections, equipment delivery and installation will continue until Q2 2023.
- Transformers delivered and installation completed.
- Auxiliary power generators received on-site in Q4 2022.
- Electrical works began in Q4 2022 with grounding grid completed and electrical conduits started.
- Battery storage containers delivery delayed by Mitsubishi to Q2 2023.
- COD might be delayed to Q3 2023 due to delay in battery delivery, but the Corporation expects to be compensated with liquidated damages from supplier.

San Andrés Battery Storage

- Environmental permit confirmed.
- Local building permits on-going.
- Earth works initiated in Q1 2023.
- Delivery of battery storage equipment planned for Q3 2023.

2- OVERVIEW OF OPERATIONS | Development Activities

Innergex owns a portfolio of projects in development stage with a gross installed capacity of approximately 365.4 MW. The table below outlines their status as at the date of this MD&A.

Name (Location)	Type	Gross installed capacity (MW)	PPA term (years)	Expected COD
Frontera (Chile)	Hydro	109.0	—[1]	—[3]
Rucacura (Chile)	Hydro	3.0	—[1]	2025
Lazenay (France)	Wind	9.0	—[1]	2023
Auxy Bois Régnier (France)	Wind	29.4	20	2025
Paeahu (Hawaii, U.S.)	Solar	15.0[2]	25	—[3]
Palomino (Ohio, U.S.)	Solar	200.0	—	2025

1. Power to be sold on the open market or through PPAs yet to be signed.
2. Solar project with a battery storage capacity of 15 MW/60 MWh (4 hours).
3. Project schedule under revision.

Updated status from the previous quarter for the following projects:

Auxy Bois Régnier
- Appeal still in progress and interconnection announced for Q1 2025.

Lazenay
- Easement contract signature underway, to be completed in Q1 2023.
- Wind turbine model has been selected and contract is under review.

Palomino
- Commercial discussions are on-going with multiple offtakers.
- Executed term sheet to secure the supply of panels for the Project.
- Ohio Power Siting Board Staff Report of Investigation recommended the Certificate of Environmental Compatibility and Public Need for the Project be issued.

Paeahu
- The Corporation will be submitting a PPA price increase and an updated construction schedule to the utility for consideration, pending a positive ruling on the contested case for the PUC.

Kahana and Barbers Point
- The PPAs of these projects were canceled by the Corporation following significant construction cost increases. These projects were moved back from projects in development stage to prospective advanced stage to participate in future request for proposals processes in Hawaii.

Boswell Springs
- This project was moved from projects in development stage to Project Under Construction.

2- OVERVIEW OF OPERATIONS | Prospective Projects

Innergex owns interests in numerous prospective projects at various stages of development. Some projects have secured land rights, filed an investigative permit application or have submitted or could submit a proposal under a Request for Proposals (collectively the "Prospective Projects"). The list of Prospective Projects is revised quarterly to add or remove projects, according to their advancement potential. Prospective projects are categorized in different stages based on the items below. There is no certainty that any Prospective Project will be realized.

In order to define the stage of each prospective project, their progression is measured according to their development maturity leading to obtaining a final notice to proceed to the construction phase combined with a success probability factor that the project will reach COD. Prospective projects are segregated into three different stages, i.e. early, mid and advanced.

Early Stage	The prospective projects in this category have a **LOW** development maturity combined with a **LOW** success probability factor; or a **MID**-stage development maturity combined with a **LOW** success probability factor.
Mid Stage	The prospective projects in this category have a **MID**-stage development maturity combined with a **MEDIUM** success probability factor; or a **HIGH**-stage development maturity combined with a **MEDIUM** success probability factor.
Advanced Stage	The prospective projects in this category have a **HIGH** development maturity combined with a **HIGH** success probability factor; or a **MID**-stage development maturity combined with **HIGH** success probability factor.

	Early Stage		Mid Stage		Advanced Stage		Total Capacity[1] (in MW)	Total number of projects
	Capacity[1] (in MW)	Number of projects	Capacity[1] (in MW)	Number of projects	Capacity[1] (in MW)	Number of projects		
CANADA								
Hydro	500	15	—	—	—	—	500	15
Solar	280	5	—	—	—	—	280	5
Wind	2,723	13	2,400	6	—	—	5,123	19
Storage	111	1	—	—	—	—	111	1
Subtotal	3,614	34	2,400	6	—	—	6,014	40
UNITED STATES								
Solar	573	6	300	1	705	5	1,578	12
Wind	—	—	400	1	—	—	400	1
Green hydrogen[2]	5	1	—	—	—	—	5	1
Subtotal	578	7	700	2	705	5	1,983	14
FRANCE								
Solar	30	2	—	—	85	1	115	3
Wind	45	2	108	6	149	8	302	16
Subtotal	75	4	108	6	234	9	417	19
CHILE								
Hydro	29	2	—	—	154	1	183	3
Solar	32	1	—	—	—	—	32	1
Wind	72	2	—	—	—	—	72	2
Subtotal	133	5	—	—	154	1	287	6
Total	4,400	50	3,208	14	1,093	15	8,701	79
Changes from Q3 2022	+137	+2	(134)	—	+185	+3	+188	+5

1. Only Gross Installed Capacity is disclosed for Prospective Projects as the net capacity is not yet defined at this stage.
2. In this table, the electrolyser was attributed to the United States until additional progress is achieved. The production is estimated at 800,000 kg per year, which corresponds to approximately 5 MW based on current assumptions.

Compared to Q3 2022, three new projects, one in Canada and two in France, were added to Early Stage projects. One existing project in the Early Stage saw an increase in capacity in France and one was moved from Early Stage project to Mid Stage. One project in the United States has advanced from Mid Stage to Advanced Stage. Two projects in the United States were moved from Project Under Development to Advanced Stage.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS

	Three months ended December 31				Year ended December 31					
	2022	2021	Change		2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized[3]	Change	
Revenues	203,636	202,388	1,248	1 %	870,494	747,208	(54,967)	692,241	178,253	26 %
Operating expenses	62,591	42,555	20,036	47 %	207,768	149,106	—	149,106	58,662	39 %
General and administrative expenses	13,568	12,813	755	6 %	53,071	45,098	—	45,098	7,973	18 %
Prospective projects expenses	7,118	9,709	(2,591)	(27)%	24,740	27,367	—	27,367	(2,627)	(10)%
Adjusted EBITDA[1]	120,359	137,311	(16,952)	(12)%	584,915	525,637	(54,967)	470,670	114,245	24 %
Finance costs	83,864	67,417	16,447	24 %	317,842	252,255	—	252,255	65,587	26 %
Other net income	(23,236)	(34,565)	11,329	33 %	(68,919)	(89,621)	—	(89,621)	20,702	23 %
Depreciation and amortization	93,756	77,748	16,008	21 %	336,053	255,640	—	255,640	80,413	31 %
Impairment of long-term assets	47,868	12	47,856	— %	47,868	36,986	—	36,986	10,882	29 %
Share of (earnings) loss of joint ventures and associates:[2]										
Share of (earnings) loss, before impairment charges	286	(791)	1,077	136 %	(14,382)	77,280	(64,197)	13,083	(27,465)	(210)%
Share of impairment charges	—	—	—	— %	—	112,609	—	112,609	(112,609)	(100)%
Change in fair value of financial instruments	(16,622)	(15,411)	(1,211)	(8)%	64,145	92,122	(72,060)	20,062	44,083	220 %
Income tax (recovery)	(12,982)	37,158	(50,140)	(135)%	(6,577)	(26,240)	17,071	(9,169)	2,592	28 %
Net (loss) earnings	(52,575)	5,743	(58,318)	(1,015)%	(91,115)	(185,394)	64,219	(121,175)	30,060	25 %
(Net loss) earnings attributable to:										
Owners of the parent	(45,301)	(2,348)	(42,953)	(1,829)%	(81,619)	(191,805)	64,219	(127,586)	45,967	36 %
Non-controlling interests	(7,274)	8,091	(15,365)	(190)%	(9,496)	6,411	—	6,411	(15,907)	(248)%
	(52,575)	5,743	(58,318)	(1,015)%	(91,115)	(185,394)	64,219	(121,175)	30,060	25 %
Basic and diluted net loss per share from continuing operations attributable to owners ($)	(0.23)	(0.02)			(0.43)	(1.09)	0.35	(0.74)		

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to such measures presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. 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.
3. For the year ended December 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

	Three months ended December 31			Year ended December 31		
Hydroelectric Segment	2022	2021	Change	2022	2021	Change
Production (MWh)	579,451	943,297	(39)%	3,331,052	3,256,828	2 %
LTA (MWh)	824,540	806,256	2 %	3,838,290	3,392,026	13 %
Revenues (in $M)	61,082	96,392	(37)%	336,645	277,302	21 %
Operating, general and administrative expenses	19,513	24,019	(19)%	86,135	64,866	33 %
Adjusted EBITDA (in $M)[1]	41,569	72,373	(43)%	250,510	212,436	18 %
PROPORTIONATE[1]						
Production Proportionate (MWh)	631,088	999,294	(37)%	3,743,181	3,738,333	— %
Revenues Proportionate (in $M)	67,264	103,899	(35)%	380,973	327,849	16 %
Adjusted EBITDA Proportionate (in $M)	45,614	77,402	(41)%	285,064	250,983	14 %

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators 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.

For the three-month period ended December 31, 2022, the decrease of 37% in Revenues in the hydroelectric segment compared with the same period last year is mainly explained by exceptionally low production at the facilities in British Columbia and at Curtis Palmer due to drier weather. The decrease was partly offset by the higher spot prices from the Chilean facilities. The decrease of 19% in Operating, general and administrative expenses is explained by lower maintenance costs at some facilities in British Columbia, partly offset by higher expenses following the Curtis Palmer Acquisition on October 25, 2021. As a result, the Adjusted EBITDA[1] decreased by 43% to $41.6 million.

For the three-month period ended December 31, 2022, the decrease of 35% in Revenues Proportionate[1] in the hydroelectric segment, mainly stems from the decrease in consolidated revenues and revenues from the joint ventures and associates due to exceptionally low production at the facilities in British Columbia due to drier weather. The proportionate impact of joint ventures and associates on Operating, general and administrative expenses decreased mainly due to the Toba Montrose facilities. As a result, the Adjusted EBITDA Proportionate[1] decreased by 41% to $45.6 million.

For the year ended December 31, 2022, the increase of 21% in Revenues in the hydroelectric segment compared with the same period last year is mainly explained by the acquisitions of Curtis Palmer on October 25, 2021, of the remaining 50% interest in Energía Llaima on July 9, 2021, for which results are now included in Innergex's consolidated revenues, and of Licán on August 3, 2021. The increase is also explained by the BC Hydro Curtailment Payment (refer to the "Contingencies" section for more information) mitigated by exceptionally low production at the facilities in British Columbia due to drier weather. The increase of 33% in Operating, general and administrative expenses is explained by higher maintenance costs at some facilities in British Columbia following the floods that occurred at the end of 2021, higher expenses following the acquisitions of Curtis Palmer, of the remaining 50% interest in Energía Llaima and of Licán. As a result, the Adjusted EBITDA[1] increased by 18% to $250.5 million.

For the year ended December 31, 2022, the increase of 16% in Revenues Proportionate[1] in the hydroelectric segment, mainly stems from the increase in consolidated revenues, which was partly offset by the decrease in joint ventures' and associates' Revenues compared to the same period last year. The decrease is mainly due to a lower contribution from the facilities in Chile since their results are now included in the Corporation's consolidated results following the acquisition of the remaining 50% interest in Energía Llaima. The proportionate impact of joint ventures and associates on Operating, general and administrative expenses decreased mainly at the Chilean facilities for the reason previously stated. As a result, the Adjusted EBITDA Proportionate[1] increased by 14% to $285.1 million.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Wind Segment

Wind Segment	Three months ended December 31			Year ended December 31				
	2022	2021	Change	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	1,530,200	1,404,694	9 %	5,635,390	4,709,425	—	4,709,425	20 %
LTA (MWh)	1,761,962	1,506,858	17 %	6,094,820	5,010,772	—	5,010,772	22 %
Revenues (in $M)	127,024	90,280	41 %	420,529	349,786	(16,801)	332,985	26 %
Operating, general and administrative expenses	39,113	16,262	141 %	103,042	72,927	—	72,927	41 %
Adjusted EBITDA (in $M)[1]	87,911	74,018	19 %	317,487	276,859	(16,801)	260,058	22 %
PROPORTIONATE[1]								
Production Proportionate (MWh)	1,570,150	1,441,697	9 %	5,761,303	5,020,531	—	5,020,531	15 %
Revenues Proportionate (in $M)	148,786	111,436	34 %	501,465	464,293	(57,107)	407,186	23 %
Adjusted EBITDA Proportionate (in $M)	108,467	94,632	15 %	394,380	385,866	(57,107)	328,759	20 %

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators 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.
2. For the year ended December 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

For the three-month period ended December 31, 2022, Revenues increased by 41% in the wind power generation segment compared with the same period last year, mainly due to the Aela Acquisition on June 9, 2022, favourable market prices from the United States facilities, and the increase in revenues from new PPAs in place at facilities in France. The increase of 141% in Operating, general and administrative expenses is mainly explained by higher expenses following the Aela Acquisition and by the impact of the 2022 Supplementary Budget Act in France on French facilities. As a result, the Adjusted EBITDA[1] increased by 19% to $87.9 million, compared with the same period last year.

For the three-month period ended December 31, 2022, the increase of 34% in Revenues Proportionate[1] mainly stems from the increase in consolidated revenues and from the joint ventures' and associates' Revenues, which increased compared to the same period last year due to higher production. There were no significant impacts from joint ventures and associates on Operating, general and administrative expenses compared with the same period last year. As a result, the Adjusted EBITDA Proportionate[1] increased by 15% to $108.5 million.

For the year ended December 31, 2022, Revenues increased by 26% in the wind power generation segment compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events. The increase is mainly due to the Aela Acquisition on June 9, 2022, the commissioning of the Griffin Trail facility on July 26, 2021, and to higher production from the facilities in Quebec. The increase of 41% in Operating, general and administrative expenses is due mainly to the Aela Acquisition, the commissioning of the Griffin Trail facility and the impact of the 2022 Supplementary Budget Act in France. As a result, the Adjusted EBITDA[1] increased by 22% to $317.5 million, compared with the same period last year, for which the Adjusted EBITDA[1] was normalized to exclude the February 2021 Texas Events.

For the year ended December 31, 2022, the increase of 23% in Revenues Proportionate[1] in the wind power generation segment compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events, was explained by the consolidated facilities and the increase of PTCs generated by the wind farms mostly due to the commissioning of the Griffin Trail facility on July 26, 2021.

This increase was partly offset by the Flat Top and Shannon facilities, for which results have been excluded from April 1, 2021, onwards, following the February 2021 Texas Events, until their effective disposal on December 28, 2021, and March 4, 2022, respectively. The proportionate impact of joint ventures and associates on Operating, general and administrative expenses decreased for the same reasons stated above. As a result, the Adjusted EBITDA Proportionate[1] increased by 20% to $394.4 million, on a normalized basis.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Solar Segment

	Three months ended December 31			Year ended December 31				
Solar Segment	2022	2021	Change	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	247,388	235,166	5 %	1,287,563	1,088,962	—	1,088,962	18 %
LTA (MWh)	313,118	270,963	16 %	1,518,991	1,257,038	—	1,257,038	21 %
Revenues (in $M)	15,530	15,716	(1)%	113,320	120,120	(38,166)	81,954	38 %
Operating, general and administrative expenses	6,747	5,309	27 %	24,299	16,418	—	16,418	48 %
Adjusted EBITDA (in $M)[1]	8,783	10,407	(16)%	89,021	103,702	(38,166)	65,536	36 %
PROPORTIONATE[1]								
Production Proportionate (MWh)	247,388	235,166	5 %	1,287,563	1,094,502	—	1,094,502	18 %
Revenues Proportionate (in $M)	15,530	15,716	(1)%	113,320	121,005	(38,166)	82,839	37 %
Adjusted EBITDA Proportionate (in $M)	8,783	10,407	(16)%	89,021	104,256	(38,166)	66,090	35 %

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators 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.
2. For the year ended December 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

For the three-month period ended December 31, 2022, Revenues decreased by 1% in the solar power generation segment compared with the same period last year, due mainly to the lower selling prices at the Salvador facility partly offset by higher average selling prices at the Phoebe facility, and the San Andrés Acquisition on January 28, 2022. The increase of 27% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Hillcrest facility and by the San Andrés Acquisition. As a result, the Adjusted EBITDA[1] decreased by 16% to $8.8 million, compared with the same period last year.

For the year ended December 31, 2022, Revenues increased 38% in the solar power generation segment compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events. The increase is mainly attributable to the higher selling prices at the Phoebe facility, the San Andrés Acquisition on January 28, 2022, and to the contribution of the Pampa Elvira facility following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021. The increase of 48% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Hillcrest facility, and the acquisition of the San Andrés and Pampa Elvira facilities. As a result, the Adjusted EBITDA[1] increased by 36% to $89.0 million, compared with the same period last year, for which the Adjusted EBITDA was normalized to exclude the February 2021 Texas Events.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Net Earnings (Loss)

Net loss of $52.6 million ($0.23 net loss per share - basic and diluted) for the three-month period ended December 31, 2022, compared with net earnings of $5.7 million ($0.02 net earnings per share - basic and diluted) for the corresponding period in 2021.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, the $58.3 million increase in net loss mainly stems from:

- a $47.9 million increase in impairment of long-term assets, mainly attributable to the impairment charges recognized in 2022 on the Hawaiian projects and on the safe harbor solar modules;
- a $16.4 million increase in finance costs mainly related to the Aela Acquisition and the Griffin Trail and Hillcrest facilities;
- a $16.0 million increase in depreciation and amortization, mainly attributable to the Aela and San Andrés acquisitions; and
- an $11.3 million decrease in other net income, mainly related to a decrease in the tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility, partly offset by a favourable shift in foreign exchange rates in 2022, compared with the same period last year.

These items were partly offset by:

- a $50.1 million decrease in income tax expense mainly due to a decrease in the tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility and to the classification of the safe harbor solar modules as assets held for sale.

Net loss of $91.1 million ($0.43 net loss per share - basic and diluted) for the year ended December 31, 2022, compared with a net loss of $185.4 million ($1.09 net loss per share - basic and diluted) for the corresponding period in 2021.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, the $94.3 million decrease in net loss mainly stems from:

- a $204.3 million decrease in the share of loss of joint ventures and associates, mainly related to:
    - the recognition of $112.6 million in impairment charges through the Corporation's share of loss of the Flat Top and Shannon joint venture facilities in 2021;
    - the February 2021 Texas Events, resulting in a net unfavourable impact of $64.2 million on the Flat Top and Shannon joint venture facilities in 2021 (refer to the "February 2021 Texas Events" section of this MD&A for more information); and
    - the recognition of a $26.9 million mark-to-market loss through the Corporation's share of loss of the Flat Top and Shannon joint venture facilities in 2021, compared to nil in 2022.
- a favourable $28.0 million change in the fair value of financial instruments, mainly related to the net unfavourable impact of the February 2021 Texas Events in 2021 and the favourable change in foreign exchange forward and interest rate curves in 2022 compared with the same period last year, partly offset by an increase in merchant power curves for the Phoebe power hedge.

These items were partly offset by:

- an $80.4 million increase in depreciation and amortization, mainly attributable to the Energía Llaima, Aela, San Andrés and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissionings in 2021;
- a $65.6 million increase in finance costs mainly related to the Energía Llaima and Aela acquisitions, an increase in inflation compensation interests on the Harrison Hydro real-return bonds and to the Griffin Trail and Hillcrest facilities commissioned in 2021;
- a $20.7 million decrease in other net income, mainly related to a decrease in the tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility, partly offset by a favourable shift in foreign exchange rates and the increase in PTCs generated due to a full production year at the Griffin Trail facility in 2022, compared with 2021;
- a $19.7 million increase in income tax expense, mainly related to the impacts of the February 2021 Texas Events, the Flat Top and Shannon impairment charges in 2021, and the non-recognition of deferred tax assets on projects classified as assets held for sale, partly offset by a decrease in income tax expense due to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility; and
- a $10.9 million increase in impairment of long-term assets following the impairment charges recognized in 2022 on the Hawaiian projects and on the safe harbor solar modules, partly offset by the impairment charges recognized in 2021 on the Phoebe solar facility, the Energía Llaima investment following the purchase of the remaining equity interests, and a minority equity investment in France.

3- FINANCIAL PERFORMANCE ON OPERATING RESULTS | Adjusted Net Loss

The Adjusted Net Loss[1] seeks to provide a measure that eliminates the earnings impacts of certain derivative financial instruments and non-recurring events, which do not represent the Corporation's operating performance. Adjusted Net Loss[1] 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.

References to "Adjusted Net Loss[1]" are to net earnings or losses of the Corporation, to which the following elements are added (subtracted): unrealized portion of the change in fair value of financial instruments; realized portion of the Phoebe basis hedge, realized loss on the termination of interest rate swaps, realized gain on foreign exchange forward contracts, impairment charges, items that are outside of the normal course of the Corporation's cash generating operations such as the February 2021 Texas Events, the net income tax expense (recovery) related to these items, and the share of losses of joint ventures and associates related to the above items, net of related tax.

The table below shows a summary statement of Adjusted Net (Loss) Earnings[1] (Please refer to the "Non-IFRS Measures" for a reconciliation to the Consolidated Statements of Earnings (Loss):

	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021 Normalized[2]
Revenues	203,636	202,388	870,494	692,241
Expenses:				
Operating expenses	62,591	42,555	207,768	149,106
General and administrative expenses	13,568	12,813	53,071	45,098
Prospective project expenses	7,118	9,709	24,740	27,367
Adjusted EBITDA[1]	120,359	137,311	584,915	470,670
Finance costs	83,864	67,417	317,842	252,255
Other net income	(23,236)	(32,372)	(65,705)	(85,547)
Depreciation and amortization	93,756	77,748	336,053	255,640
Share of loss (earnings) of joint ventures and associates	500	(272)	(12,501)	(12,423)
Realized loss on power hedges	1,559	1,672	37,479	2,902
Income tax (recovery) expense	(6,800)	33,092	6,607	64,794
Adjusted Net Loss[1]	(29,284)	(9,974)	(34,860)	(6,951)

1. Adjusted Net Loss and Adjusted EBITDA 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. For the year ended December 31, 2021, the revenues are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

Adjusted Net Loss[1] of $29.3 million for the three-month period ended December 31, 2022, compared with an Adjusted Net Loss[1] of $10.0 million for the corresponding period in 2021.

The $19.3 million increase in Adjusted Net Loss[1] mainly stems from:

- a $9.1 million decrease in other net income, mainly related to a decrease in the tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility, partly offset by a favourable shift in foreign exchange rates in 2022, compared with the same period last year;
- a $16.4 million increase in finance costs mainly related to the Aela Acquisition, and the Griffin Trail and Hillcrest facilities; and
- a $16.0 million increase in depreciation and amortization, mainly attributable to the Aela and San Andrés acquisitions.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, these items were partly offset by:

- a $39.9 million decrease in income tax expense mainly due to a decrease in the tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility.

Adjusted Net Loss[1] of $34.9 million for the year ended December 31, 2022, compared with an Adjusted Net Loss[1] of $7.0 million for the corresponding period in 2021.

The $27.9 million increase in Adjusted Net Loss[1] mainly stems from:

- an $80.4 million increase in depreciation and amortization**,** mainly attributable to the Energía Llaima, Aela, San Andrés and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissionings in 2021;
- a $65.6 million increase in finance costs mainly related to the Energía Llaima and Aela acquisitions, an increase in inflation compensation interests on the Harrison Hydro real return bonds and to the Griffin Trail and Hillcrest facilities commissioned in 2021;
- an unfavourable $34.6 million realized change in the Phoebe power hedge, mainly related to the higher merchant prices in 2022; and
- a $19.8 million decrease in other net income, mainly related to a decrease in the tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility, partly offset by a favourable shift in foreign exchange rates and the increase in PTCs generated due to a full production year at the Griffin Trail facility in 2022, compared with 2021.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, these items were partly offset by:

- a $58.2 million decrease in income tax expenses mainly due to a decrease in the tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility.

3- FINANCIAL PERFORMANCE ON OPERATING RESULTS | Non-Controlling Interests

Attribution of loss of $7.3 million to non-controlling interests for the three-month period ended December 31, 2022, compared with an attribution of earnings of $8.1 million for the corresponding period in 2021.

The $15.4 million increase in loss attributed to non-controlling interests for the three-month period ended December 31, 2022, is mainly due to:

- a decrease in revenues mainly attributable to exceptionally low production at Harrison Hydro, Kwoiek Creek and at Curtis Palmer facilities due to drier weather; and
- no allocation to the non-controlling interest in Innergex Europe in the fourth quarter of 2022 due to the French Acquisition on October 4, 2022.

Attribution of loss of $9.5 million to non-controlling interests for the year ended December 31, 2022, compared with an attribution of earnings of $6.4 million for the corresponding period in 2021.

The $15.9 million increase in loss attributed to non-controlling interests for the year ended December 31, 2022, is mainly due to:

- a decrease in revenues mainly attributable to exceptionally low production at Harrison Hydro and Kwoiek Creek facilities due to drier weather;
- a higher allocation of loss to the non-controlling interests of Harrison Hydro, largely due to an increase in the inflation compensation interest on the real return bonds, compared with the same period last year; and
- no allocation to the non-controlling interest in Innergex Europe in the fourth quarter of 2022 due to the French Acquisition on October 4, 2022.

These items were partly offset by:

- a favourable movement in the unrealized change in the fair value of derivative financial instruments in Innergex Europe.

4- CAPITAL AND LIQUIDITY | Capital Structure

The Corporation's capital structure consists of the following components, as shown below:

	As at December 31, 2022	As at December 31, 2021
Equity[1]		
Common shares[2]	3,306,952	3,580,388
Preferred shares[3]	87,640	109,080
Non-controlling interests	170,232	267,568
	3,564,824	3,957,036
Long-term loans and borrowings[1]		
Corporate revolving credit facility	718,232	398,758
Other corporate debt	305,000	295,000
Project-level debt	4,088,456	3,562,380
Tax Equity financing	443,147	455,967
Convertible debentures	282,678	280,258
Deferred financing costs	(78,303)	(67,928)
	5,759,210	4,924,435
	9,324,034	8,881,471

1.Common and preferred shares are presented at their fair value as at December 31, 2022, and December 31, 2021, while non-controlling interests and long-term loans and borrowings are presented at their respective book value.
2.Consists of the number of common shares outstanding as at December 31, 2022, and December 31, 2021, multiplied by the prevailing share price of $16.20 (2021 - $18.60) at the close of markets.
3.Consists of the number of preferred shares outstanding as at December 31, 2022, and December 31, 2021, multiplied by the prevailing share price of $13.40 and $21.04 (2021 - $17.20 and $25.30), for the Series A and Series C preferred shares, respectively, at the close of markets.

Innergex'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.

Innergex 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. Generally, equity is the primary source of financing for the development of projects, while long-term loans and borrowings are used to finance the construction projects. The Corporation expects to finance 70% to 85% of its construction costs mostly through non-recourse long-term debt financing or tax equity financing for qualifying projects in the United States.

The fair value of common shares was impacted mainly by a net unfavourable change in the share price, and by the shares issued related to the February 2022 public offering and the concurrent Hydro-Québec private placement (refer to the "Information on Capital Stock" section of this MD&A for more information). The preferred shares structure remained consistent compared to December 31, 2021. The fair value was therefore impacted by a net unfavourable change in the price of preferred shares. The decrease in non-controlling interests stems mainly from the French and the Mountain Air acquisitions, respectively, the distributions allocated to the non-controlling interests and an increase in the loss allocated to the non-controlling interests in the Harrison Hydro and Kwoiek Creek facilities during the year.

The increase in long-term loans and borrowings is mainly due to the Aela Acquisition and the subsequent refinancing of the non-recourse debt of the Chilean facilities, and the net draws from the revolving credit facility.

The effective all-in interest rate on the Corporation's long-term loans and borrowings was 5.06% as at December 31, 2022 (4.62% as at December 31, 2021).

Credit Agreements – Material Financial and Non-Financial Conditions

As at December 31, 2022, the Corporation and its subsidiaries have met all material financial and non-financial conditions related to their credit agreements, trust indentures and PPAs. When they are not met, certain financial and non-financial covenants included in the credit agreements, trust indentures and 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.

4- CAPITAL AND LIQUIDITY | 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. The TEIs are allocated a portion of the renewable energy facilites' taxable income (losses), PTCs/ITCs 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.

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 TEIs are obligated to make a cash contribution (“Pay-go Contribution”) to the Corporation. The Pay-go arrangement results 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 TEI 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 TEI derived from the power generated during the period and recognized in other net income as earned and as a reduction in tax equity financing
Investment Tax Credits ("ITC")	Allocation of ITCs to the TEI stemming from the construction activities and recognized as a reduction in both the cost of the assets to which they relate and the tax equity financing
Taxable income (loss), including tax attributes such as accelerated tax depreciation	Allocation of taxable income and other tax attributes to the TEI recognized in other net income as earned and as a reduction in tax equity financing
Interest expense	Interest expense using the effective interest rate method recognized in finance costs as incurred and as an increase in tax equity financing
Pay-go contributions	Additional cash contributions made by the TEI when the annual production exceeds the contractually determined threshold and recognized as an increase in tax equity financing
Cash distributions	Cash allocation to the TEI, recognized as a reduction in tax equity financing

Inflation Reduction Act of 2022 (IRA)
In August 2022, the Inflation Reduction Act (IRA) was passed. Among other things, the IRA provides an extension of the current ITC and PTC for projects that begin construction prior to January 1, 2025. In addition, solar projects can choose the PTC instead of just the ITC for projects starting construction before January 1, 2025. For projects placed in service after January 1, 2025, there is a transition to a new technology-neutral tax credit system, which is essentially the same in function and amount as the ITC/PTC. This new technology-neutral structure extends until power sector emissions are reduced by 75% from 2022 level or begin stepping down after 2032, whichever is later.

As at December 31, 2022, the PTC amounts to US$26/MWh generated, and subject to annual CPI inflation adjustment, and the ITC represents 30% of allowable capital costs.

Production Tax Credit Program ("PTC")

Current United States tax law allows wind energy projects to receive tax credits that are earned for each MWh of generation during the first 10 years of the projects' operation. Both Foard City and Griffin Trail were eligible for the full PTC credit.

	Commercial Operation Date	Expected TEI Flip Point[5]	TEI Investment (M$)	Expected Annual PTC Generation[3] (M$)	Expected Annual Pay-go Contribution[4] (M$)	TEI Allocation of Taxable Income (Loss) and PTCs (Pre-Flip Point)	TEI Allocation of Cash Distributions (Pre-Flip Point)
Foard City[1,2]	2019	2029	372.7	45.9	4.9	99.00 %	5.00 %
Griffin Trail[1,2]	2021	2031	210.6	29.3	5.1	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 TEI or a change to the Flip Point. Figures provided are for 2022.
2. TEIs in U.S. projects generally require certain sponsor guarantees as a condition for their investment. To support the tax equity investments at Foard City and Griffin Trail, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the TEIs 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$26/MWh generated for the period from COD to Flip Point, translated into Canadian dollars at 1.3544. PTCs generation will vary depending on actual production. PTCs are subject to annual CPI inflation.
4. Average annual Pay-go Contributions estimate is based on PTCs generated on gross estimated LTA for each year from COD to Flip Point, translated into Canadian dollars at 1.3544. Pay-go Contributions will be earned on actual production in excess of a specified annual threshold, subject to a contractual cumulative maximum.
5. Represents the expected TEI Flip Point as estimated at the date of final funding from the TEI. Actual Flip Point may differ, subject to the facilities' respective operating performance.

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. Both Phoebe and Hillcrest were eligible for the full 30% ITC.

	Commercial Operation Date	Expected TEI Flip Point[7]	TEI Investment (M$)	TEI Allocation of Taxable Income (Loss) and ITC (Pre-Flip Point)	TEI Preferred Allocation of Cash (Pre-Flip Point)
Phoebe[1,2,3,7]	2019	2026	244.3	67.00 %	10.62% in excess of priority distribution
Hillcrest[1,4,5,6,7]	2021	2028	142.2	99.00 %	4.23% 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 TEIs 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 these fixed and defined distributions are distributed at the rate of 10.62% to the TEI, until the Flip Point date.
3. Phoebe allocation of taxable income (loss) and ITC are 67.00% until December 31, 2024, and up to 99.00% thereafter, until TEI Flip Point.
4. Hillcrest Solar Partners received US$22.4 million ($29.8 million) from the TEI in return for its Class A membership interest, representing 20% of the TEI's total investment. The remaining funding of US$90.4 million ($122.4 million) was received upon commissioning of the project on November 2021.
5. Hillcrest allocation of taxable income (loss) and ITCs is 99.00% to the TEI. From January 1, 2027, allocation of taxable income (loss) to the TEI will be 5.00%.
6. Hillcrest's cash distribution amounts to the TEI are fixed and defined within the TEI partnership agreement. All amounts of distributable cash in excess of these fixed and defined distributions are distributed at the rate of 4.23% to the TEI, until the Flip Point date.
7. Represents the expected TEI Flip Point as estimated at the date of final funding from the TEI. Actual Flip Point may differ, subject to the facilities' respective operating performance.

4- CAPITAL AND LIQUIDITY | Financial Position

As at	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	162,971	166,266
Restricted cash	54,670	61,659
Investment tax credits recoverable	1,282	1,200
Other current assets	249,019	159,552
Assets held for sale	59,217	—
Total current assets	527,159	388,677
Non-current assets		
Property, plant and equipment	6,212,371	5,513,392
Intangible assets	1,268,960	1,043,994
Investments in joint ventures and associates	135,786	133,398
Goodwill	139,676	60,858
Other non-current assets	318,475	255,749
Total non-current assets	8,075,268	7,007,391
Total assets	8,602,427	7,396,068
LIABILITIES		
Current liabilities	650,824	733,527
Non-current liabilities		
Long-term loans and borrowings	5,384,813	4,411,239
Other non-current liabilities	1,080,363	890,622
Total non-current liabilities	6,465,176	5,301,861
Total liabilities	7,116,000	6,035,388
SHAREHOLDERS' EQUITY		
Equity attributable to owners	1,316,195	1,093,112
Non-controlling interests	170,232	267,568
Total shareholders' equity	1,486,427	1,360,680
	8,602,427	7,396,068

Working Capital Items

As at December 31, 2022, working capital[1] was negative at $123.7 million, from negative $344.9 million in 2021, mainly explained by:

- Current assets amounted to $527.2 million as at December 31, 2022, an increase of $138.5 million compared with December 31, 2021, mainly due to a $61.4 million increase in accounts receivable, attributable mainly to the Aela Acquisition and the timing of collection therewith, the reclassification of the safe harbor solar modules as held for sale, and an $11.3 million increase in prepaid and other, attributable mainly to the Aela Acquisition.

- Current liabilities amounted to $650.8 million as at December 31, 2022, a decrease of $82.7 million compared with December 31, 2021, mainly due to a $137.7 million decrease in the current portion of long-term loans and borrowings, which primarily relates to the resolution of breaches under the Phoebe, Duqueco, Beaumont and Vallottes project loans, partly offset by the classification of the $150.0 million subordinated unsecured term loan as current, due to its February 6, 2023 maturity and by the Aela and San Andrés acquisitions.

- Derivative financial instruments also contributed favourably to the working capital balance (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information).

The Corporation considers its current level of working capital[1] and revolving term credit facility availability to be sufficient to meet its needs, also considering the $150.0 million subordinated unsecured term loan, effectively refinanced on February 1, 2023, classified as current as at December 31, 2022. As at December 31, 2022, the Corporation had $950.0 million in revolving term credit facility and had drawn $718.2 million as cash advances, while $56.9 million had been used to issue letters of credit, leaving $174.9 million available.

Non-Current Assets

Non-current assets amounted to $8,075.3 million as at December 31, 2022, an increase of $1,067.9 million compared with December 31, 2021. The increase is mainly due to an aggregate addition of $939.8 million to property, plant and equipment and intangible assets as part of the Aela and San Andrés acquisitions. Moreover, the construction and development activities also contributed to an increase in property, plant and equipment and project development costs by an aggregate amount of $175.2 million, net of the ITC recoverable recognized against the project construction costs of Hale Kuawehi. An increase of $73.1 million in goodwill, following the Aela Acquisition, an increase in the right of use of assets following an upward revision in the wind and solar facilities' useful lives and an increase of $18.3 million in deferred tax assets mainly related to the Mountain Air Acquistion and tax losses allocated to Phoebe, partly offset by the reversal of previously recognized tax losses in Chile, also contributed to the increase in non-current assets. Derivative financial instruments also favourably impacted non-current assets (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information). In addition, the increase is also explained by a weakening of the Canadian dollar against the United States dollar and the Euro.

These items were partly offset by depreciation and amortization of $336.1 million, by an upward shift in interest rate curves, which contributed to the decrease of the asset retirement obligations included in property, plant and equipment, and by the impairment charges recognized on the Hawaiian projects and on the safe harbor solar modules.

Non-Current Liabilities

Non-current liabilities amounted to $6,465.2 million as at December 31, 2022, an increase of $1,163.3 million compared with December 31, 2021. The increase is mainly due to a $973.6 million increase in the non-current portion of long-term loans and borrowings, stemming from the long-term loans and borrowings assumed in the Aela Acquisition and the subsequent refinancing of the non-recourse debt of the Chilean facilities, and from net draws on the revolving term credit facility, used toward the San Andrés Acquisition and the construction and development activities.

The classification of project loans as non-current following the resolution of breaches under the Phoebe, Duqueco, Beaumont and Vallottes credit agreements also contributed to the increase in the non-current portion of long-term loans and borrowings (see the "Capital Structure" section of this MD&A for more information). In addition, the increase in non-current liabilities is also explained by a $136.2 million increase in deferred tax liabilities, largely related to the Aela Acquisition and to a favourable change in the fair value of the derivative financial instruments, the lease liabilities acquired in the Aela Acquisiton and an increase in the lease liabilities following an upward revision in the wind and solar facilities' useful lives.

[1] Working capital represents the excess or deficiency of current assets over current liabilities.

These items were partly offset by the scheduled principal repayments of long-term loans and borrowings, and the classification of the subordinated unsecured term loan as current due to its February 6, 2023 maturity. In addition, the upward shift in interest rate curves contributed to a decrease of the asset retirement obligations.

Shareholders' Equity

As at December 31, 2022, Shareholders' equity increased by $125.7 million compared with December 31, 2021, mainly attributable to the shares issued as part of the public offering in February 2022 and the concurrent Hydro-Québec private placement (please refer to the "Information on Capital Stock" section of this MD&A for more information), and the total comprehensive income of $176.1 million, partly offset by the dividends declared on common and preferred shares totalling $152.6 million, the distributions to non-controlling interests totalling $48.7 million, and the acquisition of non-controlling interests through the French and the Mountain Air acquisitions.

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.

The aggregate fair value of derivative financial instruments amounted to a net asset of $25.3 million as at December 31, 2022, from a net liability of $59.4 million as at December 31, 2021. The favourable change relates mainly to the interest hedging derivatives, favourably impacted by an upward shift in the interest rate curves, and the foreign exchange forward contracts, favourably impacted by a general downward shift in the Euro/CAD forward curve. These items were partly offset by the unfavourable change in the Phoebe power hedge, following an increase in the merchant price curves, and the monetization of the Euro/CAD foreign exchange forward contracts concurrent with the closing of the French Acquisition.

Off-Balance-Sheet Arrangements

As at December 31, 2022, the Corporation had issued letters of credit totalling $300.6 million, including $56.9 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 $113.4 million in corporate guarantees used mainly to guarantee certain activities of prospective projects. The corporate guarantees were also used to support the long-term currency hedging instruments of its operations in France, payment security related to its development activities in Hawaii, and the performance of the Brown Lake and Miller Creek hydroelectric facilities.

Tax equity investors in U.S. projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investments at Kokomo, Spartan, Foard City, Phoebe, Hillcrest, Griffin Trail and Mountain Air, Alterra Power Corp, 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 in favour of the project, which will become effective only in the unlikely event that the Phoebe tax equity investors call upon their guarantee.

4- CAPITAL AND LIQUIDITY | Contingencies

BC Hydro Curtailment Notices

In May 2020, Innergex received notices from BC Hydro in relation to six of the Corporation’s hydroelectric facilities in British Columbia stating that BC Hydro would not accept and purchase energy under the applicable electricity purchase agreements (“EPAs”) above a specified curtailment level for the period from May 22, 2020 to July 20, 2020. The specified curtailment levels were 0.0 MW/h for the Jimmie Creek (accounted for using the equity method), Upper Lillooet River, Northwest Stave River, and Boulder Creek facilities, 2.0 MW/h for the Tretheway Creek facility and 4.0 MW/h for the Big Silver Creek facility.

BC Hydro cited the COVID-19 pandemic and related governmental measures taken in response to it as constituting a “force majeure” event under the EPAs, and resulting in a situation in which BC Hydro was allegedly unable to accept or purchase energy under the EPAs. The notices to Innergex followed public statements by BC Hydro regarding measures it was taking to address the reduced electricity demand during the COVID-19 pandemic and related challenges to the safe operation of its hydroelectric system.

Innergex disputed that the pandemic and related governmental measures in any way prevented BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enabled it to invoke “force majeure” provisions under the EPAs to suspend these obligations. Innergex acknowledges that BC Hydro retains “turn-down” rights under the EPAs, which enable it to require Innergex to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk. Where BC Hydro exercises this right, it is required under the EPAs to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. Innergex complied with BC Hydro’s curtailment request, but did so under protest, seeking to enforce its rights under the EPAs on the basis described above. For the period from May 22, 2020 to July 20, 2020, actual eligible energy revenue that would have been produced at the facilities in the absence of the curtailment amounted to $12.5 million ($14.2 million on a Revenues Proportionate[1] basis). The dispute was settled in the first quarter of 2022 to Innergex's satisfaction.

Harrison Hydro L.P. Water Rights

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 $3.2 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 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. The Limited Partnerships have filed their response to petition on April 14, 2020. The hearing took place in Victoria in the last week of September 2020. A decision was rendered on February 9, 2021, by the Supreme Court of British Columbia, which concluded that the Environmental Appeal Board's decision was reasonable, and dismissed the Comptroller of Water Rights' petition accordingly. The Comptroller of Water Rights subsequently appealed the decision of the Supreme Court of British Columbia; the appeal was unanimously dismissed by the British Columbia Court of Appeal on January 7, 2022. The Corporation recognized the amount of $3.2 million in the consolidated statements of earnings (loss) during the year ended December 31, 2019. A total amount of $3.4 million, including interest, was received by the Corporation during the first quarter of 2022.

Innavik EPC Agreement

On January 25, 2023 a legal hypothec has been registered by the contractor against the Innavik hydroelectric project ("Innavik" or "the project"), a joint venture company, in the amount of $57.8 million, representing the contractor's claim for payment of additional costs under the EPC Agreement with Innavik. The Corporation disputes that claim in good faith and, unless the contractor discharges the legal hypothec at its request, will take legal action to cause the legal hypothec to be removed from title. As at December 31, 2022, while continuing to dispute the claim, the project recognized a provision for construction cost overruns, estimated based on a range of possible outcomes that are materially lower than the amounts claimed by the contractor.

[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.

4- CAPITAL AND LIQUIDITY | Cash Flows

	Three months ended December 31		Year ended December 31			
	2022	2021	2022	2021	February 2021 Texas Events (9 days)	2021 Normalized [1]
OPERATING ACTIVITIES						
Cash flows from operating activities	93,631	75,837	430,243	265,498	17,093	282,591
FINANCING ACTIVITIES						
Cash flows (used in) from financing activities	(24,009)	366,228	197,536	414,077	—	414,077
INVESTING ACTIVITIES						
Cash flows used in investing activities	(127,768)	(446,083)	(635,766)	(667,054)	—	(667,054)
Effects of exchange rate changes on cash and cash equivalents	4,266	(4,766)	4,692	(7,720)	—	(7,720)
Net change in cash and cash equivalents	(53,880)	(8,784)	(3,295)	4,801	17,093	21,894
Cash and cash equivalents, beginning of period	216,851	175,050	166,266	161,465	—	161,465
Cash and cash equivalents, end of period	162,971	166,266	162,971	166,266	17,093	183,359

1.Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

Cash Flows from Operating Activities

For the three-month period ended December 31, 2022, cash flows from operating activities totalled $93.6 million, compared with $75.8 million in the same period last year. The increase relates primarily to the realized gain on financial instruments following the monetization of the foreign exchange forward contracts concurrent with the closing of the French Acquisition, to the Aela and San Andrés acquisitions, and to the timing of interest payments for certain BC project debts in Q4 2022, partly offset by an increase in finance costs paid relative to the Green Bonds issued as part of a refinancing of the non-recourse debt in Chile following the Aela Acquisition.

For the year ended December 31, 2022, cash flows from operating activities totalled $430.2 million, compared with $265.5 million in the same period last year. The increase relates primarily to the contribution from the Energía Llaima, Licán, Curtis Palmer, San Andrés and Aela acquisitions, the Hillcrest and Griffin Trail commissionings, and the BC Hydro Curtailment Payment. The realized gain on financial instruments following the settlement of both the interest rate swaps, as part of Innergex's refinancing of the non-recourse debt of its Chilean facilities and the foreign exchange forward contracts concurrent with the closing of the French Acquisition, the net unfavourable impact of the February 2021 Texas Events, and the timing of interest payments for certain BC project debts in Q4 2022, also contributed to increased cash flows from operating activities. These items were partly offset by an increase in finance costs paid mainly related to the Griffin Trail and Hillcrest facilities commissioned in 2021 and to the Green Bonds issued as part of a refinancing of the non-recourse debt in Chile following the Aela Acquisition and from the unfavourable difference between sales at the Phoebe node and purchases at the ERCOT South hub.

Cash Flows (used in) from Financing Activities

For the three-month period ended December 31, 2022, cash flows used in financing activities totalled $24.0 million, compared with cash flows from financing activities of $366.2 million in the same period last year. The decrease stems mainly from the $196.7 million investment made by HQI US Holding LLC, a subsidiary of Hydro-Québec, in the Curtis Palmer Acquisition in 2021 and by a net $23.9 million increase in long-term loans and borrowings in 2022, mainly explained by lower scheduled debt principal repayments, compared to a net increase of $217.1 million in 2021, mainly related to draws made on the corporate revolving credit facility toward the Curtis Palmer Acquisition.

For the year ended December 31, 2022, cash flows from financing activities totalled $197.5 million, compared with $414.1 million in the same period last year. The decrease stems mainly from the $196.7 million investment made by HQI US Holding LLC, a subsidiary of Hydro-Québec in the Curtis Palmer Acquisition in 2021, and from the $202.4 million cash inflow in 2022 from shares issued related to the Aela Acquisition, compared to the $267.8 million cash inflow in 2021 from shares issued related to the Curtis Palmer Acquisition. These items were partly offset by the net $208.0 million increase in long-term loans and borrowings in 2022, mainly explained by the San Andrés and Aela acquisitions, the Green Bonds issued as part of a refinancing of the non-recourse debt in Chile following the Aela Acquisition, and the additions to property, plant and equipment, compared to an increase of $114.6 million in 2021, mainly related to net draws made toward the construction of the Griffin Trail and Hillcrest facilities.

Cash Flows Used in Investing Activities

For the three-month period ended December 31, 2022, cash flows used in investing activities totalled $127.8 million, compared with $446.1 million in the same period last year. This decrease is mainly due to the consideration paid toward the Curtis Palmer Acquisition in 2021.

For the year ended December 31, 2022, cash flows used in investing activities totalled $635.8 million, compared with $667.1 million in the same period last year. The decrease in cash flows used in investing activities is mainly due to the additions to property, plant and equipment of the Griffin Trail and Hillcrest facilities in 2021, partly offset by the consideration paid toward the San Andrés and Aela acquisitions and the Mountain Air Acquisition in 2022, compared with the consideration paid toward the Curtis Palmer Acquisition in 2021.

4- CAPITAL AND LIQUIDITY | Free Cash Flow and Payout Ratio

Free Cash Flow and Payout Ratio calculation[1]	Year ended December 31				
	2022	2021	February 2021 Texas Events (9 days)[7]	2021 Normalized[7]	2020
Cash flows from operating activities[2]	430,243	265,498	17,093	282,591	235,108
Add (Subtract) the following items:					
Changes in non-cash operating working capital items	14,518	21,455	—	21,455	7,765
Maintenance capital expenditures, net of proceeds from disposals	(11,051)	(8,029)	—	(8,029)	(2,828)
Scheduled debt principal payments	(156,862)	(160,973)	—	(160,973)	(151,623)
Free Cash Flow attributed to non-controlling interests[3]	(29,271)	(25,076)	—	(25,076)	(13,491)
Dividends declared on Preferred shares	(5,632)	(5,632)	—	(5,632)	(5,942)
Chile portfolio refinancing - hedging impact[4]	2,578	—	—	—	—
Add (subtract) the following specific items[5]:					
Realized loss on contingent considerations	—	547	—	547	3,021
Realized (gain) loss on termination of interest rate swaps[4]	(71,735)	2,508	—	2,508	1,664
Realized (gain) loss on termination of foreign exchange forwards[6]	(43,458)	—	—	—	—
Acquisition, integration and restructuring costs	17,918	4,563	—	4,563	—
Realized gain on the Phoebe basis hedge	—	(2,546)	(1,304)	(3,850)	19,586
Free Cash Flow[7]	147,248	92,315	15,789	108,104	93,260
Dividends declared on common shares	146,957	132,229	—	132,229	125,543
Payout Ratio[7]	100 %	143 %	(21)%	122 %	135 %
Adjust for the following items:					
Prospective projects expenses	24,740			27,367	16,708
Adjusted Free Cash Flow	171,988			135,471	109,968
Adjusted Payout Ratio	85 %			98 %	114 %

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. Cash flows from operating activities for the year ended December 31, 2022 include the one-time BC Hydro Curtailment Payment received during the first quarter of 2022.
3. 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.
4. The Free Cash Flow for the year ended December 31, 2022 excludes the $71.7 million realized gain on settlement of the interest rate hedges entered into to manage the Corporation's exposure to the risk of increasing interest rates during the negotiations surrounding the refinancing of the non-recourse debt assumed in the Aela Acquisition and at Innergex's existing Chilean projects. Instead, the gain is amortized in the Free Cash Flow using the effective interest rate method over the period covered by the unwound hedging instruments.
5. These items are excluded from the Free Cash Flow and Payout Ratio calculations as they are deemed not representative of the Corporation's long-term cash-generating capacity, and include items such as gains and losses on the Phoebe basis hedge due to their limited occurrence (maturity attained on December 31, 2021), realized gains and losses on contingent considerations related to past business acquisitions, transaction costs related to realized acquisitions, realized losses or gains on refinancing of certain borrowings or derivative financial instruments used to hedge the interest rate on certain borrowings or the exchange rate on equipment purchases, and tax payments related to fiscal strategies for the purpose of improving the long-term cash generating capacity of Innergex.
6. The Free Cash Flow for the year ended December 31, 2022 excludes the $43.5 million realized gain on settlement of the foreign exchange forward contracts concurrent with the closing of the French Acquisition.
7. For the year ended December 31, 2021, the Free Cash Flow and Payout Ratio are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

Free Cash Flow

For the year ended December 31, 2022, the Corporation generated Free Cash Flow[1] of $147.2 million, compared with $92.3 million for the corresponding period last year (Normalized Free Cash Flow[1,2] of $108.1 million, when excluding the impacts from the February 2021 Texas Events - refer to the "February 2021 Texas Events" section of this MD&A for more information).

Free Cash Flow[1] increased $39.1 million compared with Normalized Free Cash Flow[1,2] in the comparative period, mainly due to:

- the contribution to cash flows from operating activities before changes in non-cash operating working capital items from the Energía Llaima, Licán, Curtis Palmer, San Andrés and Aela acquisitions, and from the Hillcrest and Griffin Trail commissionings;
- the timing of principal and interest payments for certain BC project debts; and
- an increase in revenues from the BC Hydro Curtailment Payment.

These items were partly offset by:

- an increase in Free Cash Flow attributed to non-controlling interests, stemming mainly from the Curtis Palmer Acquisition, partly offset by a decrease attributed to the Harrison Hydro facilities, mainly explained by exceptionally low production in British Columbia in Q4 2022 due to drier weather;
- an increase in the interest paid relative to Chile refinancing Green Bonds in Q4 2022; and
- a decrease in cash flows from operating activities before changes in non-cash operating working capital items from the Phoebe facility, due mostly to an unfavourable difference between sales at the Phoebe node and purchases at the ERCOT South hub.

Payout Ratio

For the year ended December 31, 2022, the dividends on common shares declared by the Corporation amounted to 100% of Free Cash Flow[1], compared with 143% for the corresponding period last year. Excluding the impacts from the February 2021 Texas Events (please refer to the "February 2021 Texas Events" section of this MD&A for more information), the dividends on common shares declared by the Corporation for the corresponding period last year amounted to 122% of Normalized Free Cash Flow[1,2].

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[1] Free Cash Flow 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.

[2] Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

4- CAPITAL AND LIQUIDITY | Information on Capital Stock

The Corporation's Equity Securities

	As at		
	February 21, 2023	December 31, 2022	December 31, 2021
Number of common shares	204,160,610	204,132,833	192,493,999
Number of 4.75% convertible debentures	148,023	148,023	148,023
Number of 4.65% convertible debentures	142,056	142,056	142,056
Number of Series A Preferred Shares	3,400,000	3,400,000	3,400,000
Number of Series C Preferred Shares	2,000,000	2,000,000	2,000,000
Number of stock options outstanding	284,769	284,769	265,570

As at the closing of the market on February 21, 2023, and since December 31, 2022, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 27,777 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at December 31, 2022, the increase in the number of common shares since December 31, 2021, was mainly due to the following:

– the issuance of 9,718,650 common shares as part of the public offering closed on February 22, 2022. Concurrently with the closing of the offering, the Corporation issued 2,100,000 common shares to Hydro-Québec to maintain its ownership;
– the issuance of 57,949 common shares related to the DRIP.

These items were partly offset by:

– the 253,681 common shares purchased and cancelled by the Corporation under the Normal Course Issuer Bid terminated on May 23, 2022, for a total cash consideration of $4.6 million.

New Normal Course issuer Bid

The Corporation received approval from the Toronto Stock Exchange ("TSX") to renew the normal course issuer bid on its common shares and to commence a normal course issuer bid on its Series A preferred shares and Series C preferred shares (the "New Bid"). Under the New Bid, the Corporation could purchase for cancellation up to 4,082,073 of its common shares, representing approximately 2% of the 204,103,658 issued and outstanding common shares of the Corporation as at May 11, 2022. The Corporation could purchase for cancellation up to 68,000 of its Series A preferred shares, representing approximately 2% of the 3,400,000 issued and outstanding Series A preferred shares of the Corporation as at May 11, 2022. The Corporation could purchase for cancellation up to 40,000 of its Series C preferred shares, representing approximately 2% of the 2,000,000 issued and outstanding Series C preferred shares of the Corporation as at May 11, 2022. The New Bid commenced on May 24, 2022, and will terminate on May 23, 2023.

4- CAPITAL AND LIQUIDITY | 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			
	2022		2021		2022		2021	
	($/share)	Total	($/share)	Total	($/share)	Total	($/share)	Total
Dividends declared on common shares[1]	0.180	36,744	0.180	34,649	0.7200	146,957	0.7200	132,229
Dividends declared on Series A Preferred Shares	0.2028	689	0.2028	689	0.8110	2,757	0.8110	2,757
Dividends declared on Series C Preferred Shares	0.3594	719	0.3594	719	1.4375	2,875	1.4375	2,875

1. The increase in dividends declared on common shares was attributable to the issuances of common shares upon acquisitions, public offerings, Hydro-Québec private placements, and to the issuance of common shares under the DRIP, partly offset by common shares purchased and cancelled under the NCIB.

The following dividends will be paid by the Corporation on April 17, 2023:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
February 22, 2023	March 31, 2023	April 17, 2023	$0.180	$0.202750	$0.359375

5- OUTLOOK | 2022 Guidance Achievements

In 2022, the Corporation partly met its 2022 Growth Targets.

	2022			2021
	Actual		Target[3]	Actual Normalized[2]
Production (GWh)[1]	10,254	**+13 %**	+22 %	9,055
Revenues	870,494	**+26 %**	+25 %	692,241
Operating, general, administrative and prospective projects expenses	285,579	**+29 %**	+27 %	221,571
Adjusted EBITDA[1]	584,915	**+24 %**	+25 %	470,670
Adjusted EBITDA Proportionate[1]	696,362	**+20 %**	+21 %	578,472
Free Cash Flow per Share[1]	0.72		0.75	0.6
Number of facilities in operation	84		84	79
Net installed capacity (MW)	3,634		3,484	3,101

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production 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.
2. For the year ended December 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.
3. Target revised in August 2022. Please refer to the MD&A for the period ended June 30, 2022.

The Production target was not met mainly due to:
- Exceptionally low hydrology levels in British Columbia during the later part of 2022;
- Lower generation from the US facilities; and
- Other weather-related events.

The financial targets were partly met due to the following factors:
- Exceptionally low hydrology levels in British Columbia during the later part of 2022;
- The enactment of the new 2022 Supplementary Budget Act in France, which aims to share additional revenues recognized for certain power purchase agreements with the French government.

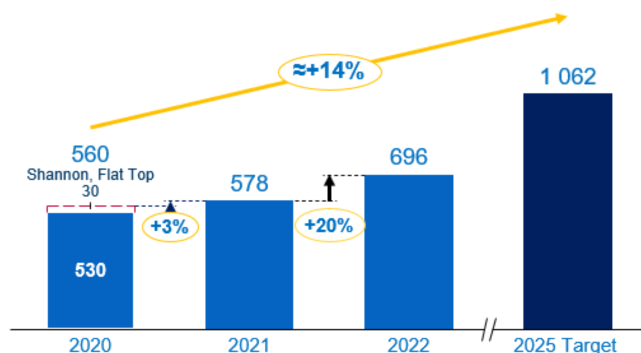
Partly mitigated by higher prices at the Chilean and US facilities.

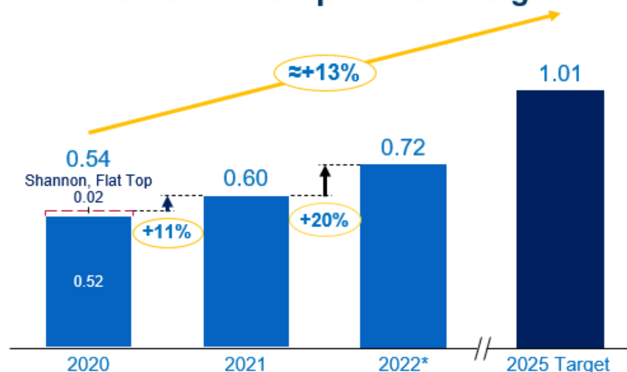
5- OUTLOOK | Strategic Plan 2020-2025

The targets of the Corporation are to achieve, on a run rate basis, an Adjusted EBITDA Proportionate[1] compound annual growth rate of approximately 14% by 2025 to $1.062 billion and a Free Cash Flow[1] per Share compound annual growth rate of approximately 13% by 2025 to $1.01.

The following graphs present the targets for 2025 on a run rate basis.

[1] These measures 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.





Innergex's continued growth will come from a balanced strategy of developing greenfield projects with a deferred cash contribution profile and strategic acquisitions in current markets with nearer-term cash contributions. The projected figures above includes potential transactions or projects that could be achieved or developed as part of the Strategic Alliance with Hydro-Québec.

The Corporation presents the outlook for the 2020-2025 Strategic Plan to provide readers with an indication of its business activities and operating performance. This outlook for the 2020-2025 Strategic Plan presented in this section is based on certain assumptions, which include:

- The realization of the growth plan to reach 6,000 MW of gross installed capacity based on a strategic mix of development activities and acquisitions of operating assets;
- Average hydrology, wind regimes and solar irradiation projections leading to a 100% LTA target for all facilities;
- Successful renewal of PPAs taking into consideration potential pressure on pricing;
- Escalation on contractual PPAs;
- Increase in the investment in prospective expenses to meet growth plan;
- No material changes in the industry's market conditions and financial opportunities;
- No material adverse impacts to the long-term investment and credit markets;
- Sufficient human resources to deliver service and execute the capital plan;
- Favourable market conditions for share issuance to support growth financing;
- No significant variability in interest rates;
- Average merchant spot prices consistent with external price curves and internal forecasts;
- No severe and prolonged economic downturn;
- Continued maintenance of information technology infrastructure and no material breach of cybersecurity;
- No significant event occurring outside the ordinary course of business such as a natural disaster, pandemic or other calamity;
- No material changes in the assumed U.S. dollar to Canadian dollar and Euro to Canadian dollar exchange rate;
- An average inflation rate based on historical trend; and
- An increase in salaries based on market average assumptions.

These assumptions are based on information currently available to the Corporation and this list of assumptions is not exhaustive. These assumptions, although considered reasonable by the Corporation on February 22, 2023, may prove to be inaccurate. Important risks and uncertainties may cause actual results or performance to be materially different from the Corporation's expectations as set forth in this section. The risks and uncertainties are referred to in the "Risks and Uncertainties" section of the Annual Report.

6- 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 Innergex's production and cash generation capabilities, its ability to sustain current dividends and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods. Revenues Proportionate, Adjusted EBITDA, Adjusted EBITDA Proportionate, Adjusted Net Loss, 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, Adjusted EBITDA and corresponding Proportionate measures

References in this document to "Revenues Proportionate" are to Revenues, plus Innergex's share of Revenues of the joint ventures and associates, other income related to PTCs, and Innergex's share of the operating joint ventures' and associates' other income related to PTCs.

References in this document to “Adjusted EBITDA” are to net earnings (loss), to which are added (deducted) income tax expense (recovery), finance costs, depreciation and amortization, impairment charges, other net income, share of (earnings) loss of joint ventures and associates, and change in fair value of financial instruments. References in this document to "Adjusted EBITDA Proportionate" are to Adjusted EBITDA, plus Innergex's share of Adjusted EBITDA of the joint ventures and associates, other income related to PTCs, and Innergex's share of other income related to PTCs of the joint ventures and associates.

Innergex believes that the presentation of these measures enhances the understanding of the Corporation's operating performance. Adjusted EBITDA is used by investors to evaluate the operating performance and cash generating operations, and to derive financial forecasts and valuations. Revenues Proportionate and Adjusted EBITDA Proportionate measures are used by investors to evaluate the contribution of the joint ventures and associates to the Corporation’s operating performance and cash generating operations, and the contribution of such for financial forecasts and valuations purposes. In addition, Revenues Proportionate and Adjusted EBITDA Proportionate measures help investors seize the relative importance of PTCs generated by the operations, and evaluate their contribution to the Corporation’s operating performance, as PTCs form an important part of certain wind projects’ economics in the United States. Readers are cautioned that Revenues Proportionate, should not be construed as an alternative to Revenues, as determined in accordance with IFRS. Readers are also cautioned that Adjusted EBITDA and Adjusted EBITDA Proportionate, should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Financial Performance and Operating Results" section for more information.

Below is a reconciliation of the non-IFRS measures to their closest IFRS measures:

	Three months ended December 31, 2022				Three months ended December 31, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	203,636	11,368	16,576	231,580	202,388	12,259	16,404	231,051
Net earnings (loss)	(52,575)	—	—	(52,575)	5,743	—	—	5,743
Income tax expense	(12,982)	—	—	(12,982)	37,158	—	—	37,158
Finance costs	83,864	4,362	—	88,226	67,417	4,541	—	71,958
Depreciation and amortization	93,756	4,155	—	97,911	77,748	4,241	—	81,989
Impairment of long-term assets	47,868	—	—	47,868	12	—	—	12
EBITDA	159,931	8,517	—	168,448	188,078	8,782	—	196,860
Other net expense (income), before PTCs	(6,660)	(105)	—	(6,765)	(18,161)	219	—	(17,942)
Production tax credits ("PTCs")	(16,576)	—	16,576	—	(16,404)	—	16,404	—
Share of earnings of joint ventures and associates	286	(286)	—	—	(791)	791	—	—
Change in fair value of financial instruments	(16,622)	(101)	—	(16,723)	(15,411)	(553)	—	(15,964)
Adjusted EBITDA	120,359	8,025	16,576	144,960	137,311	9,239	16,404	162,954

	Year ended December 31, 2022				Year ended December 31, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	870,494	60,535	64,729	995,758	747,208	111,921	54,018	913,147
Net loss	(91,115)	—	—	(91,115)	(185,394)	—	—	(185,394)
Recovery of Income tax	(6,577)	—	—	(6,577)	(26,240)	(31)	—	(26,271)
Finance costs	317,842	17,757	—	335,599	252,255	23,382	—	275,637
Depreciation and amortization	336,053	16,801	—	352,854	255,640	23,051	—	278,691
Impairment of long-term assets	47,868	—	—	47,868	36,986	112,609	—	149,595
EBITDA	604,071	34,558	—	638,629	333,247	159,011	—	492,258
Other net expense (income), before PTCs	(4,190)	(342)	—	(4,532)	(41,637)	1,947	—	(39,690)
Production tax credits ("PTCs")	(64,729)	—	64,729	—	(47,984)	(6,034)	54,018	—
Share of (earnings) loss of joint ventures and associates	(14,382)	14,382	—	—	189,889	(189,889)	—	—
Change in fair value of financial instruments	64,145	(1,880)	—	62,265	92,122	129,055	—	221,177
Adjusted EBITDA	584,915	46,718	64,729	696,362	525,637	94,090	54,018	673,745

Adjusted Net Loss

References to "Adjusted Net Loss" are to net earnings or losses of the Corporation, to which the following elements are added (subtracted): unrealized portion of the change in fair value of derivative financial instruments; realized portion of the Phoebe basis hedge, realized loss on the termination of interest rate swaps, realized gain on foreign exchange forward contracts, impairment charges, items that are outside of the normal course of the Corporation's cash generating operations such as the February 2021 Texas Events, the net income tax expense (recovery) related to these items, and the share of loss (earnings) of joint ventures and associates related to the above items, net of related income tax.

The Adjusted Net Loss seeks to provide a measure that eliminates the earnings impacts of certain derivative financial instruments and other items that are outside of the normal course of the Corporation's cash generating operations, which do not represent the Corporation's operating performance. Innergex uses derivative financial instruments to hedge its exposure to various risks. Accounting for derivatives requires that all derivatives are marked-to-market. When hedge accounting is not applied, changes in the fair value of the derivatives is recognized directly in net earnings (loss). Such unrealized changes have no immediate cash effect, may or may not reverse by the time the actual settlements occur and do not reflect the Corporation's business model toward derivatives, which are held for their long-term cash flows, over the whole life of a project. In addition, the Corporation uses foreign exchange forward contracts to hedge its net investment in its French subsidiaries. Management therefore believes realized gains (losses) on such contracts does not reflect the operations of Innergex.

Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Adjusted Net Loss is used by investors to evaluate and compare Innergex's profitability before the impacts of the unrealized portion of the change in fair value of derivative financial instruments and other items that are outside of the normal course of the Corporation's cash generating operations. Readers are cautioned that Adjusted Net Loss 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.

Below is a reconciliation of Adjusted Net Loss to its closest IFRS measure:

	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021
Net (loss) earnings	(52,575)	5,743	(91,115)	(185,394)
Add (Subtract):				
February 2021 Texas Events:				
Revenues	—	—	—	(54,967)
Power hedge	—	—	—	70,756
Share of loss of Flat Top and Shannon	—	—	—	64,197
Share of impairment of Flat Top and Shannon	—	—	—	112,609
Share of unrealized portion of the change in fair value of financial instruments of joint ventures and associates, net of related income tax	(76)	(377)	(1,381)	20,226
Unrealized portion of the change in fair value of financial instruments	25,336	(15,751)	141,859	18,502
Impairment of long-term assets	47,868	12	47,868	36,986
Realized gain on settlement of foreign exchange forwards	(43,458)	—	(43,458)	—
Realized (gain) loss on termination of interest rate swaps	(59)	(377)	(71,735)	2,508
Realized gain on the Phoebe basis hedge	—	(955)	—	(2,546)
Realized gain on foreign exchange forward contracts	—	(2,193)	(3,214)	(4,074)
Income tax recovery related to above items	(6,320)	3,924	(13,684)	(85,754)
Adjusted Net loss	(29,284)	(9,974)	(34,860)	(6,951)

Below is a reconciliation of Adjusted Net Loss adjustments to each line item of the consolidated statements of earnings:

	Three months ended December 31						Year ended December 31					
	2022			2021			2022			2021		
	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS
Revenues	203,636	—	203,636	202,388	—	202,388	870,494	—	870,494	747,208	(54,967)	692,241
Operating expenses	62,591	—	62,591	42,555	—	42,555	207,768	—	207,768	149,106	—	149,106
General and administrative expenses	13,568	—	13,568	12,813	—	12,813	53,071	—	53,071	45,098	—	45,098
Prospective projects expenses	7,118	—	7,118	9,709	—	9,709	24,740	—	24,740	27,367	—	27,367
Adjusted EBITDA	120,359	—	120,359	137,311	—	137,311	584,915	—	584,915	525,637	(54,967)	470,670
Finance costs	83,864	—	83,864	67,417	—	67,417	317,842	—	317,842	252,255	—	252,255
Other net income	(23,236)	—	(23,236)	(34,565)	2,193	(32,372)	(68,919)	3,214	(65,705)	(89,621)	4,074	(85,547)
Depreciation and amortization	93,756	—	93,756	77,748	—	77,748	336,053	—	336,053	255,640	—	255,640
Impairment of long-term assets	47,868	(47,868)	—	12	(12)	—	47,868	(47,868)	—	36,986	(36,986)	—
Share of (earnings) losses of joint ventures and associates	286	214	500	(791)	519	(272)	(14,382)	1,881	(12,501)	189,889	(202,312)	(12,423)
Change in fair value of financial instruments	(16,622)	18,181	1,559	(15,411)	17,083	1,672	64,145	(26,666)	37,479	92,122	(89,220)	2,902
Income tax (recovery) expense	(12,982)	6,182	(6,800)	37,158	(4,066)	33,092	(6,577)	13,184	6,607	(26,240)	91,034	64,794
Net (loss) earnings	(52,575)	23,291	(29,284)	5,743	(15,717)	(9,974)	(91,115)	56,255	(34,860)	(185,394)	178,443	(6,951)

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, the portion of Free Cash Flow attributed to non-controlling interests, and preferred share dividends declared, plus or minus other elements that are not representative of the Corporation's long-term cash-generating capacity, such as gains and losses on the Phoebe basis hedge due to their limited occurrence, realized gains and losses on contingent considerations related to past business acquisitions, transaction costs related to realized acquisitions, realized losses or gains on refinancing of certain borrowings or derivative financial instruments used to hedge the interest rate on certain borrowings or the exchange rate on equipment purchases, and tax payments related to fiscal strategies for the purpose of improving the long-term cash generating capacity of Innergex.

The Payout Ratio is a measure of the Corporation's ability to sustain current dividends as well as its ability to fund its growth from its cash generating operations, in the normal course of business. 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.

Innergex believes that the presentation of this measure enhances the understanding of the Corporation's cash generation capabilities, its ability to sustain current dividends and its ability to fund its growth. Free Cash Flow is used by investors in this regard. 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. Adjusted Free Cash Flow is used by investors to evaluate the Corporation's cash generation capabilities and its ability to sustain current dividends, before the impacts of the Corporation's decision to invest yearly in its growth through investing in the development of its Prospective Projects.

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 as well as its ability to fund its growth. Payout Ratio is used by investors in this regard.

References to "Adjusted Payout Ratio" are to dividends declared on common shares divided by Adjusted Free Cash Flow. Adjusted Payout Ratio is used by investors to evaluate the Corporation's ability to sustain current dividends, before the impacts of the Corporation's decision to invest yearly in its growth through investing in the development of its Prospective Projects.

7- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Non-current Assets

	As at	
	December 31, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets[1]		
Canada	3,246,979	3,390,029
United States	2,364,160	2,301,353
Chile	1,549,679	423,856
France	753,161	801,752
	7,913,979	6,916,990

1. Includes the investments in joint ventures and associates.

7- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Revenues

	Year ended December 31	
	2022	2021
Revenues		
Canada	427,910	433,192
United States	229,446	187,332
Chile	121,021	38,091
France	92,117	88,593
	870,494	747,208

7- ADDITIONAL CONSOLIDATED INFORMATION | Historical Quarterly Financial Information

(in millions of dollars, unless otherwise stated)	Dec 31, 2022	Sept 30, 2022	June 30, 2022	March 31, 2022	Dec 31, 2021	Sept 30, 2021	June 30, 2021	March 31, 2021
Production (MWh)	2,357,039	2,736,471	2,855,891	2,304,600	2,583,157	2,290,086	2,396,027	1,785,947
Revenues	203.6	258.4	219.7	188.7	202.4	184.6	170.6	189.7
Operating, general and administrative and prospective projects expenses	83.3	77.2	66.9	58.2	65.1	62.1	47.9	46.6
Adjusted EBITDA[1]	120.4	181.2	152.9	130.5	137.3	122.5	122.7	143.1
Net (loss) earnings	(52.6)	21.0	(24.6)	(34.9)	5.7	(23.5)	50.2	(217.9)
Net (loss) earnings attributable to owners of the parent	(45.3)	23.3	(25.2)	(34.4)	(2.3)	(16.4)	41.1	(214.2)
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.23)	0.11	(0.13)	(0.18)	(0.02)	(0.10)	0.23	(1.24)
Dividends declared on common shares	36.7	36.7	36.7	36.7	34.6	34.7	31.4	31.4
Dividends declared on common shares, $ per share	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180

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.

The Corporation's production, revenues, net earnings and cash flows are variable with each season, depending on the geography and source of energy. Please refer to the "Overview of Operations | Business Environment - Seasonality of Operations" section of this MD&A for more information on seasonality.

FEBRUARY 2021 TEXAS EVENTS – SUPPLEMENTAL INFORMATION

Innergex's Presence in Texas

Name	Location	Type	Status	Sponsor Equity Ownership %	Gross installed capacity (MW)	Contract Type
Foard City	Foard County	Wind	Operating	100	350.3	Power Purchase Agreement and Merchant Price
Phoebe	Winkler County	Solar	Operating	100	250.0	Power Hedge
Flat Top	Mills County	Wind	Operating	51	200.0	Power Hedge
Shannon	Clay County	Wind	Operating	50	204.0	Power Hedge
Griffin Trail	Knox and Baylor Counties	Wind	Operating	100	225.6	Merchant Price

1. TEXAS EVENTS DESCRIPTION

- In February 2021, unprecedented extreme winter weather conditions and related electricity market failure paralyzed the State of Texas, United States. These unprecedented extreme winter weather events pushed the Texas Government to declare a disaster and the US Government to declare a state of emergency.
- The storm disrupted production, transmission and distribution of power, severely impacting prices. Because of the disturbance, wholesale electricity prices in the Electric Reliability Council of Texas (ERCOT) reached their cap of US$9,000 per MWh and remained at such level for a prolonged period of time.
- The February 2021 Texas Events lasted from February 11 to February 19, 2021, and the figures provided hereinafter are normalized for this period.

1.1 Summary of Impacts per Facility

The following table presents a reconciliation of the Production and financial impacts, before income tax, resulting from the February 2021 Texas Events, detailed by facility:

	For the 9-day period from February 11 to February 19, 2021							
	Production (MWh)	LTA (MWh)	Hedge obligation (MWh)[1]	Hedge price (US$)	Revenues	Power hedge	Basis hedge	Total Financial impacts
Consolidated facilities								
Foard City	29,464	35,175	N/A	18.13	16,801	—	—	16,801
Phoebe	5,996	14,550	13,473	33.10	38,166	(70,756)	(1,304)	(33,894)
Total - Consolidated facilities					54,967	(70,756)	(1,304)	(17,093)
Joint venture facilities								
Flat Top	2,046	24,507	19,152	22.60	15,316	(113,609)	—	(98,293)
Shannon	15,546	18,533	15,480	26.20	64,989	(93,123)	—	(28,134)
Total - Joint venture facilities								(126,427)
Total - Innergex's share of loss of the joint venture facilities								(64,197)
Total - Consolidated financial impact, before income tax								(81,290)

1. Hedge obligations are based on hourly commitments in MWh. Therefore, actual production is not always indicative of the hedge obligation fulfillment.

2. FINANCIAL IMPACTS AND NORMALIZED FINANCIAL INFORMATION

2.1 Impacts to Consolidated Statement of Earnings

The Phoebe facility is subject to power hedges. In addition, prior to their sale on December 28, 2021, and March 4, 2022, respectively, the Flat Top and Shannon facilities were also subject to power hedges. For facilities subject to power hedges, the power that is generated by the facility is delivered to the grid at the project's node (point of delivery) at the prevailing merchant prices. Production delivered at the node at merchant prices is recognized by Innergex as revenue. Under the power hedges, the hourly contracted energy is virtually purchased at the point of withdrawal on the grid ("Hub"), subject to the prevailing merchant prices, and exchanged for the contractual fixed price per MWh. Settlements under the power hedges are recognized as change in fair value of financial instruments.

The following table presents a reconciliation of the February 2021 Texas Events' impacts to the Consolidated Statement of Earnings, for each line-item impacted by the events:

		Year ended December 31, 2021		
		As presented	Impacts from the February 2021 Texas Events (9 days)	Normalized
1	Revenues	747,208	(54,967)	692,241
	Adjusted EBITDA[1]	525,637	(54,967)	470,670
2	Change in fair value of financial instruments	(92,122)	72,060	(20,062)
3	Share of losses (earnings) of joint ventures and associates	(189,889)	64,197	(125,692)
	(Loss) Earnings before income tax	(211,634)	81,290	(130,344)

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.

(1) Although power generation was depressed by the weather, **revenues at the Foard City and Phoebe facilities were favourably impacted by the events**, with revenues of $16.8 million and $38.2 million, respectively, for an aggregate impact of $55.0 million, as a result of the unprecedented increase in market prices prevailing at the point of delivery on the grid ("Node").

(2) Conversely, the change in fair value of financial instruments was unfavourably impacted by a $70.8 million **realized loss on the Phoebe power hedge**, and $1.3 million on the Phoebe basis hedge, for an aggregate impact of $72.1 million, resulting from the unprecedented increase in market prices prevailing at the point of withdrawal on the grid ("Hub"), for the committed power hedge hourly volumes.

(3) The Flat Top and Shannon joint ventures were similarly impacted by an increase in their respective revenues and realized losses on their respective power hedges, resulting in a share of losses of joint ventures and associates of $50.1 million and $14.1 million for Flat Top and Shannon, respectively, aggregating to a net $64.2 million **unfavourable impact on the share of losses of joint ventures and associates**.

The following table presents a reconciliation of the February 2021 Texas Events' impacts to the segmented information:

	Year ended December 31, 2021				
	Hydro	Wind	Solar	Unallocated	Total
Revenues	277,302	349,786	120,120	—	747,208
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Revenues[2]	277,302	332,985	81,954	—	692,241
Revenues Proportionate[1]	327,849	464,293	121,005	—	913,147
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Revenues Proportionate[1,2]	327,849	407,186	82,839	—	817,874
Adjusted EBITDA[1]	212,436	276,859	103,702	(67,360)	525,637
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Adjusted EBITDA[1,2]	212,436	260,058	65,536	(67,360)	470,670
Adjusted EBITDA Proportionate[1]	250,983	385,866	104,256	(67,360)	673,745
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Adjusted EBITDA Proportionate[1,2]	250,983	328,759	66,090	(67,360)	578,472

1. These measures 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. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers.

2.2 Impacts to Free Cash Flow and Payout Ratio

The following table presents a reconciliation of the February 2021 Texas Events' cash impacts:

		For the 9-day period from February 11 to February 19, 2021		
Facility	Impact	Cash	Non-Cash	Total
Foard City	Revenues	16,801	—	16,801
Phoebe	Revenues	38,166	—	38,166
Phoebe	Power hedge	(70,756)	—	(70,756)
Phoebe	Basis hedge	(1,304)	—	(1,304)
Flat Top	Share of loss	—	(50,129)	(50,129)
Shannon	Share of loss	—	(14,068)	(14,068)
		(17,093)	(64,197)	(81,290)

For the year ended December 31, 2021, the February 2021 Texas Events, whose cash impacts are detailed above, have impacted the Free Cash Flow[1] and Payout Ratio[1] as follows:

		Year ended December 31, 2021		
		As presented	Impacts from the February 2021 Texas Events (9 days)	Normalized[2]
1	Cash flows from operating activities before changes in non-cash operating working capital items	286,953	17,093	304,046
2	Realized gain on the Phoebe basis hedge	(2,546)	(1,304)	(3,850)
	Free Cash Flow[1]	92,315	15,789	108,104
	Dividends declared on common shares	132,229	—	132,229
	Payout Ratio[1]	143 %	(21)%	122 %

1. Free Cash Flow and Payout ratio measures 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. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers.

(1) Cash flows from operating activities before changes in non-cash operating working capital items were impacted by a net unfavourable amount of $17.1 million, representing the February 2021 Texas Events' realized losses on the Phoebe power and basis hedges, partly offset by the favourable impact to the consolidated revenues. The $64.2 million non-cash share of losses of joint ventures and associates does not directly impact cash flows from operating activities before changes in non-cash operating working capital items. It will, however, affect the joint ventures' future capacity to distribute cash to the Corporation.
(2) In the Free Cash Flow[1] and Payout Ratio[1] calculation, Innergex reverses the impacts of the Phoebe basis hedge due to its limited occurrence, which are deemed not to represent the long-term cash-generating capacity of Innergex. As such, $1.3 million is reversed from the recurring adjustment, representing the February 2021 Texas Events' related realized loss on the basis hedge.

1. Free Cash Flow and Payout ratio measures 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.

3. IMPAIRMENT

Following the February 2021 Texas Events, which caused significant losses for facilities under power hedge contracts, a general increase in the assessed risk has been observed throughout the industry for facilities subject to shape risk[2] in this region. While the other key assumptions remained largely consistent as compared to December 31, 2020, the above factors contributed to increased discount rates to reflect higher risk premiums. On March 31, 2021, the Flat Top and Shannon joint ventures, each identified as separate cash generating units ("CGU"), recognized impairment charges of US$83.0 million ($105.4 million) and US$92.7 million ($117.7 million), respectively. The impairment charges were recognized by the Corporation through its share of loss of joint ventures and associates, at $53.8 million and $58.8 million, for Flat Top and Shannon, respectively.

The recoverable amount of each CGU was determined based on a value in use calculation that uses cash flow projections based on financial budgets approved by management covering a period extending to the period for which the Corporation owns its rights on the site, and discounted at a rate of 12%.

2. Shape risk exists when there is a mismatch, or a potential mismatch, between the volume commitment under a power hedge instrument, and the actual production of the facility at a given time. For various reasons, it may happen that a facility's electricity output at a given time is below the contractual volume. In such instances, the project cannot fully cover its hub purchases with its node sales and is therefore exposed to merchant prices on its purchases at the hub.

4. MANAGEMENT'S STRATEGIES

4.1 Procedures Initiated

Phoebe

- As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedge of the Phoebe facility in February, which was rejected by the recipient.
- On July 19, 2021, Innergex reached an agreement to settle the amounts that remained unpaid by the Phoebe solar facility following the February 2021 Texas Events. The aggregate cash disbursement of US$24.0 million ($29.7 million) comprises the agreed-upon settlement payment for the amounts disputed following the February 2021 Texas Events, and a payment on the project's tracking account balance, net of unpaid energy sold by the project during the negotiation process.

Flat Top and Shannon

- As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedges of the Flat Top and Shannon facilities in February, which were rejected by the recipient.
- To preserve the Corporation's and its partners' rights with regard to the Flat Top and Shannon facilities, court proceedings were initiated on April 21, 2021.
- On May 20, 2021, the District Court of Harris County, Texas denied the temporary injunction application, directing the counterparty to the power hedges for the Flat Top and Shannon wind facilities to suspend all remedies against the projects, including foreclosure, arising from an alleged default of payment that was formally disputed by Innergex, following the February 2021 Texas Events. As a result of the Court's decision, the counterparty to the power hedges for the projects will not be precluded from exercising any of its remedies, including foreclosure.

4.2 Decisions and Actions

Phoebe

- During the year ended December 31, 2021, an impairment charge of $24.7 million was recognized, reflecting an outlook of higher than expected congestion charges, combined with a higher discount rate to reflect higher risk premiums for facilities under power hedge contracts in Texas.

Flat Top and Shannon

- The carrying amount of the Flat Top and Shannon investments was decreased to nil following the aggregate $112.6 million non-cash impairment charges on these facilities as at March 31, 2021.
- During the period ended June 30, 2021, the underlying assets and liabilities of the Flat Top and Shannon investments were classified as disposal groups held for sale.
- The deferred tax liabilities related to the Corporation's equity investments in Flat Top and Shannon were nil following the aggregate $39.5 million deferred tax recovery upon reclassification of the projects' assets and liabilities as disposal groups held for sale during the period ended June 30, 2021.
- On December 28, 2021, the Corporation completed the sale of its 51% interest in Flat Top for a nominal amount.
- On March 4, 2022, the Corporation completed the sale of its 50% interest in Shannon for a nominal amount.
- The impact of the sale of the Flat Top and Shannon facilities on the Corporation's Free Cash Flow[1], based on the facilities' respective 2020 contribution, represents a reduction of approximately $4.2 million annually.
- The sale of the Flat Top and Shannon facilities also represents an avoided cash outflow of US$60.2 million ($75.7 million), representing the share of the invoiced amounts attributable to the Corporation, which Innergex would have had funded through an equity contribution in the facilities.

1. Free Cash Flow and Payout ratio measures 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.

8- ACCOUNTING POLICIES AND INTERNAL CONTROLS | Significant Accounting Policies

New Accounting Standards and Interpretations Adopted During the Year

On January 1, 2022, the Corporation adopted the following new standards and interpretations:

Amendments to IAS 16, Property, Plant and Equipment - Proceeds before Intended Use

On May 14, 2020, the IASB issued *Property, Plant and Equipment — Proceeds before Intended Use* (Amendments to IAS 16). The amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. The amendments are effective for annual reporting periods commencing on or after January 1, 2022. The Corporation adopted the amendments on January 1, 2022, with no impact to the consolidated financial statements.

New accounting standards and interpretations issued but not yet effective

Classification of Liabilities as Current or Non-current (Amendments to IAS 1)

On January 23, 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to clarify the classification of liabilities as current or non-current. On October 31, 2022, the IASB issued Non-current Liabilities with Covenants (Amendments to IAS 1) (the "2022 amendments"), to improve the information a company provides about long-term debt with covenants. The 2020 amendments and the 2022 amendments (collectively “the Amendments”) are effective for annual periods beginning on or after January 1, 2024. Early adoption is permitted. The impact for the Corporation is being assessed by management.

Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)

On February 12, 2021, the IASB issued Disclosure Initiative – Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2 Making Materiality Judgements). The key amendments include:

- requiring companies to disclose their material accounting policies rather than their significant accounting policies;
- clarifying that accounting policies related to immaterial transactions, other events or conditions are themselves immaterial and as such do not need to be disclosed;
- clarifying that not all accounting policies that relate to material transactions, other events or conditions are themselves material to a company’s financial statements.

The amendments are effective for annual periods beginning on or after January 1, 2023. Early adoption is permitted.

8- ACCOUNTING POLICIES AND INTERNAL CONTROLS | Internal Controls

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 it 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 it to be evaluated under their supervision, the effectiveness of the Corporation’s DC&P and ICFR as at December 31, 2022, and have concluded that they were effective at the financial year-end. During the period beginning on October 1, 2022, and ended on December 31, 2022, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

9- RISKS AND UNCERTAINTIES

Corporate Risk Management and Board Oversight

The Corporation is committed to proactive strong risk governance and oversight practices supported by the Board of Directors and members of the management.

The Board of Directors is responsible to review and assess material risks associated with the Corporation's business, which may adversely affect it, its activities, its financial condition or reputation. More specifically, the Board of Directors ensures that the Corporation has implemented systems to effectively identify, manage and monitor the principal risks associated with its business and to mitigate or reduce their potential negative impacts. The Board of Directors receives updates on specific risks and risk mitigation activities from management and each of the relevant committee.

Responsibility for risk management is shared across the organization from each segment of activities. The Investment and Risk Oversight Committee, which is comprised of senior management members, reviews all existing and emerging risks and assesses appropriate mitigation measures. The Committee also supervises, among others, the management of risks inherent to investment management. Risk oversight also occurs at the level of operating subsidiaries of the Corporation, to ensure that risks are efficiently managed at every level of its corporate structure. New risks or important risks are identified and reported together with mitigation plans and discussed across all levels of the Corporation's corporate structure. The risks that have been identified, which may affect certain aspects of the activities of the Corporation or which are encountered in decision-making processes, are presented to the Board of Directors at each meeting, either by its committees or the officers of the Corporation. Such risks are presented in relation to conjuncture, strategy and in relation to any proposed transactions presented to the Board of Directors. The Board of Directors takes an active role discussing risk management with its committees to ensure that risks are properly identified, assessed and effectively managed at all levels of the Corporation's activities. Internal audit is an additional tool to validate the effectiveness and efficiency of risk management across all aspects of the Corporation's business.

The Corporation maintains policies and a Code of conduct, applicable to all directors, officers and employees of the Corporation and those of its subsidiaries, as well as any consultant or other person when representing the Corporation. Such policies and Code of conduct are reviewed at least annually by the Board of Directors. These policies and the Code of conduct aim to promote sound risk management throughout the Corporation, to delegate authority appropriately among its officers and to set limits for authorizations required to approve and execute certain business transactions. As part of such policies, the officers of the Corporation are responsible for maintaining effective communication with the Board of Directors and the employees of the Corporation, to implement and promote a culture of efficient risk management throughout the Corporation's activities. Through strategic planning approved by the Board of Directors, the officers are also responsible to assess the risk management activities. The Board of Directors' risk management oversight aims to ensure that risks are identified, reduced and mitigated, where possible. However, these risks cannot always be identified or be completely eliminated from the Corporation's activities.

The Corporation is exposed to various risks and uncertainties and has outlined below those that it considers material. 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. Those risks could have a material adverse effect on the Corporation's business, operations, financial condition and results.

Risks Related to Operations

Performance of Major Counterparties

The Corporation enters into a variety of agreements with third-party suppliers. Should one or more major counterparties be unable to meet their obligations under the contracts, this would result in unexpected costs, losses and delays for the Corporation.

Equipment Supply

The Corporation's development and operation of power generating facilities is dependent on the supply of equipment from third parties. Equipment pricing, production timeline, or delivery delay may rapidly increase depending, among other things, on equipment availability, raw material prices and on the market for such products. Any significant increase in the price, or delays to supply the 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.

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 that could cause such delays or cost overruns 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.

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 currently 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.

Equipment Failure or Unexpected Operations and Maintenance Activity

The Corporation's facilities are subject to the risk of equipment failure due to the deterioration of the asset from use or age, latent defect and design or operator error, among other things. To the extent that a facility's equipment requires longer-than-forecast 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.

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, Idaho Power Company 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.

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 Quebec, BC, Ontario in Canada, Idaho and New York in the 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.

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.

Assessment of Water, Wind and Solar Resources 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 irradiation; (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 climate change; (v) the accuracy of assumptions on a variety of factors, including but not limited to weather, ice build-up on wind turbines and snow accumulation and soiling on solar panels, site access, wake and transmission 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 risk that 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 and the Corporation's power generation could increase or decrease depending on the duration and magnitude of the changes.

Extreme weather events create a risk of physical damage to the Corporation’s assets and power outages and increase the potential likelihood of disruptions to its generation and transmission facilities. As a result, the Corporation could suffer costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially affect the Corporation’s business, including results of operations and cash flows, and its reputation with customers, investors, local communities, regulators, governments and financial markets. Resulting costs could include reconstruction, repower, regeneration, asset replacement, increased insurance premium and any losses incurred by third parties.

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 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 irradiation, 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 that may provoke unforeseen deviations from historical trends.

Preparedness to Facing Natural Disasters and Force Majeure

The Corporation’s facilities, operations and projects 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 events. The occurrence of a significant event that disrupts or delays the ability of the Corporation’s power generation assets to produce or sell power for an extended period, including events that 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, power hedges or other agreements with third parties. Furthermore, force majeure events affecting the Corporation's assets could result in damages to the environment or harm third parties. In addition, many of the Corporation’s projects are in remote areas, making access for repair of damage difficult.

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 the Corporation's 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.

Pandemics, Epidemics or Other Public Health Emergencies

The Corporation’s business, results of operations, financial condition, cash flows and stock price can be adversely affected by pandemics, epidemics or other public health emergencies, which may result in governments around the world implementing increasingly stringent measures to help control the spread of pathogens, including quarantines, “shelter in place” and “stay at home” orders, travel restrictions, business curtailments, school closures, and other measures. In addition, governments and central banks in several parts of the world may enact fiscal and monetary stimulus measures to counteract the impacts of such public health emergencies. Business disruptions could impact our suppliers, which in turn could impact the operating results of the Corporation. Should an outbreak become widespread, procurement of equipment and spare parts may be impacted and construction, operation and maintenance of the Corporation’s assets may be halted or delayed and negatively impact the business, financial condition and results of operations of the Corporation.

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, personal information and confidential information leak (or identity theft), malicious software or other violations on the system that controls generation and transmission at any of our offices or facilities could severely disrupt or otherwise affect business operations. Such attacks on our data information base systems through theft, alteration or destruction and the inability to recover promptly could impact individuals, business partners, our operation capabilities, generate unexpected expenses impacting profitability, damage the Corporation's reputation and result in additional liabilities (e.g. investigation, litigation, fines, remedial action).

With the continuous evolution of cyberattacks and having most employees working from home, the Corporation is reviewing its cybersecurity program and adapting it to this new reality. The Corporation continuously takes measures to secure its infrastructure against potential cyberattacks that may damage its infrastructure, systems, and data. The Corporation has implemented mandatory security user awareness training on security & data privacy. It also implemented security controls to help secure its data and business operations including access control measures, intrusion detection and prevention systems, logging and monitoring of network activities, and implementing policies and procedures to ensure the secure operations of the business.

Reliance on Shared Transmission and Interconnection Infrastructure

The six Harrison Operating Facilities, the Northwest Stave River Facility, the Tretheway Creek Facility and the Big Silver Creek Facility (the “Sharing Facilities”) all share joint transmission and interconnection infrastructure to transmit their electrical energy generation to a joint substation, which then interconnects to the common point of interconnection for the Sharing Facilities at the adjacent BC Hydro Upper Harrison terminal substation. Therefore, damage to or a failure of the shared transmission and interconnection infrastructure may result in the Sharing Facilities being unable to deliver their electrical energy generation to the point of interconnection with BC Hydro’s transmission system in accordance with the requirements for sale of energy under the PPAs with BC Hydro in respect of the six Harrison Operating Facilities, the Northwest Stave River Facility, the Tretheway Creek Facility and the Big Silver Creek Facility. All six Harrison Operating Facilities also share one common interconnection agreement with BC Hydro and act as agent for the Northwest Stave Facility, the Tretheway Creek Facility and the Big Silver Creek Facility. Therefore, a default by any one of the Sharing Facilities of its obligations under the interconnection agreement may result in BC Hydro disconnecting all the Sharing Facilities from the BC Hydro transmission system.

Risks Related to Corporate Strategy

Inability 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 realize 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 therefor in a manner that supports the Corporation's strategy in a timely fashion.

Inability 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.

Inability to Secure New PPAs or Renew Any PPA

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.

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.

Volatility of Supply and Demand in the Energy Market

A portion of the Corporation's revenues are tied, either directly or indirectly, to the wholesale market price for electricity in the markets in which the Corporation operates. Wholesale market electricity prices are impacted by a number of factors including the management of generation and the amount of excess generating capacity relative to load in a particular market; the structure of the electricity market; and weather conditions (such as extremely hot or cold weather) that impact electrical load.

There is uncertainty surrounding the trend in electricity demand growth, which is notably influenced by macroeconomic conditions; absolute and relative energy prices; and energy conservation and demand-side management. Therefore, from a supply perspective, there are uncertainties associated with the timing of generating plant retirements that are in part driven by environmental regulations, and by the scale, pace and structure of replacement capacity.

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 operating 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 Foard City Wind Farm, the Phoebe Solar Farm and the Salvador 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 during such time the Corporation is forced to sell electrical power generated at market price, or increase significantly, when the Corporation is forced to purchase third party power at merchant prices, the economic prospects of the operating facilities that rely, in whole or in part, on merchant prices, such as the Foard City Wind Farm, the Phoebe Solar Farm, the Salvador Solar Farm, the Griffin Trail Wind Farm, the Licán Hydro Facility, the Miller Creek Facility or development projects in which the Corporation has an interest, could be significantly reduced or rendered uneconomic. A material reduction or increase in such prices, as applicable, 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 Phoebe Solar Farm.

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.

Inability 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 of 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 could 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.

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. Those changes could also adversely affect the revenues of the Corporation.

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.

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 and solar 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.

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 are extremely complex and often require 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.

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 that 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.

Inability 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.

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, (v) changes in international and local taxation and (vi) excessive concentration of assets in single foreign market.

Risks Related to Financing

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 that 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.

Interest Rate Fluctuations and Refinancing

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.

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 a 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 EBITDA and free cash flow may be lower than expected or reduced, which would respectively impact the payout ratio.

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.

Other Risks

Possibility that the Corporation May Not Declare a Dividend or May Rreduce the Amount of the 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. The declaration and the amount 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 Corporation's 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.

Insufficiency of Insurance Coverage

While the Corporation maintains insurance coverage it believes would be maintained by a prudent owner/operator of similar facilities or projects, 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 or insured, nor that the amounts of insurance will be sufficient to cover each and every loss or claim that may occur involving our activities or assets. Insurance coverage of project assets and facilities may be prescribed by project financing agreements and/or PPAs. In addition, the Corporation may undertake construction or pursue acquisitions where obtaining insurance may be difficult, not economically feasible or otherwise insufficient to cover each and every loss or claim that may occur involving the new assets or activities. There are certain elements of the Corporation's business which are not insured, either as is customary in the industry, or where the cost of coverage is not economically viable. Insurance policies are generally subject to annual review by the respective insurers and there is no certainty that equivalent or more favourable terms will be offered upon each renewal. A significant loss, that is uninsured or significantly exceeding the limits of insurance policies, or the failure to renew insurance policies on equivalent or more favourable terms, could materially affect the Corporation's business, including results of operations and cash flows, and its reputation with customers, investors, lenders, regulators, governments and financial markets.

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. 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.

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 Cumulative Rate Reset Preferred Shares, Series A and Cumulative Redeemable Fixed Rate Preferred Shares, Series C (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, revenues from such facilities on the electricity market or under the applicable power purchase agreement will vary. An increase in the volatility of spot price would add uncertainty to the determination of potential revenues and adjusted EBITDA and could have an adverse impact on the Corporation’s results.

Host Country Economic, Social and Political Conditions

Several of the Corporation’s principal assets are located in foreign domiciles. Although the operating environments in these jurisdictions are considered favourable compared to those 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 unfavourable legislation.

Host country economic, social and political uncertainty can arise as a result of a lack of support for our activities in local communities in the vicinity of Innergex's 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 the Corporation's 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 Innergex's properties and 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.

Reliance on Intellectual Property and Confidentiality Agreements to Protect the Corporation's Rights and Confidential Information

The Corporation’s success and competitive position are dependent in part upon its 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 the 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 loss of business opportunities, loss of revenue, litigation and a reduction in the Corporation’s ability to raise additional capital. Reputational harm could also reduce the Corporation's 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.

10- 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 growth targets, 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 with Hydro-Québec), 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 targeted production, the estimated targeted revenues, targeted Revenues Proportionate, targeted Adjusted EBITDA and targeted Adjusted EBITDA Proportionate, targeted Free Cash Flow, targeted Free Cash Flow per Share 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, acquisitions and commissioned projects; project performance; availability of capital resources and timely performance by third parties of contractual obligations; favourable market conditions for share issuance to support growth financing; favourable economic and financial market conditions; the Corporation’s success in developing and constructing new facilities; successful renewal of PPAs; sufficient human resources to deliver service and execute the capital plan; no significant event occurring outside the ordinary course of business such as a natural disaster, pandemic or other calamity; continued maintenance of information technology infrastructure and no material breach of cybersecurity. Please refer to Section 5 - OUTLOOK | Strategic Plan 2020-2025 regarding the assumptions used with respect to the 2025 growth targets.

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: performance of major counterparties; equipment supply; delays and cost overruns in the design and construction of projects; health, safety and environmental risks; equipment failure or unexpected operations and maintenance activity; variability of installation performance and related penalties; increase in water rental cost or changes to regulations applicable to water use; availability and reliability of transmission systems; assessment of water, wind and solar resources and associated electricity production; global climate change; variability in hydrology, wind regimes and solar irradiation; preparedness to facing natural disasters and force majeure; pandemics, epidemics or other public health emergencies; cybersecurity; reliance on shared transmission and interconnection infrastructure; inability of the Corporation to execute its strategy for building shareholder value; inability to raise additional capital and the state of the capital market; inability to secure new PPAs or renew any PPA; reliance on various forms of PPAs; volatility of supply and demand in the energy market; fluctuations affecting prospective power prices; uncertainties surrounding development of new facilities; obtainment of permits; inability to realize the anticipated benefits of completed and future 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; regulatory and political risks; risks related to U.S. production and investment tax credits, changes in U.S. corporate tax rates and availability of tax equity financing; exposure to many different forms of taxation in various jurisdictions; social acceptance of renewable energy projects; relationships with stakeholders; inability to secure appropriate land; foreign market growth and development risks; liquidity risks related to derivative financial instruments; interest rate fluctuations and refinancing; financial leverage and restrictive covenants governing current and future indebtedness; changes in general economic conditions; foreign exchange fluctuations; possibility that the Corporation may not declare a dividend or may reduce the amount of the dividend; insufficiency of insurance coverage; ability to attract new talent or to retain officers or key employees; litigation; credit rating may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; revenues from certain facilities will vary based on the market (or spot) price of electricity; host country economic, social and political conditions; adverse claims to

property title; reliance on intellectual property and confidential agreements to protect the Corporation's 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.

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 Trudel
Jean Trudel, MBA
Chief Financial Officer

Innergex Renewable Energy Inc.

Longueuil, Canada, February 22, 2023

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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 statements of financial position as at December 31, 2022 and December 31, 2021;
- the consolidated statements of earnings (loss) for the years then ended;
- the consolidated statements of comprehensive income (loss) for the years then ended;
- the consolidated statements of changes in shareholders' equity for the years then ended;
- the consolidated statements of cash flows for the years 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, 2022 and December 31, 2021, and its consolidated financial performance and its consolidated cash flows for the years 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 ethical 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.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2022. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Evaluation of the acquisition date fair values of intangible assets and property, plant and equipment related to business acquisitions

Description of the matter

We draw attention to Notes 2, 3 and 4 to the financial statements. On June 9, 2022, the Entity acquired all of the ordinary shares of Aela Generacion S.A. and Aela Energia SpA, for an aggregate consideration of $408,160.

In connection with this transaction, the Entity recorded intangible assets of $283,778 and property, plant and equipment of $620,453.

The fair value of the intangible assets related to power purchase agreements has been established using a with-or-without approach by calculating the excess of the power purchase agreement prices over the merchant prices for the generation that would have otherwise been sold in the market. The fair value of property, plant and equipment was established using a discounted cash flow approach.

The Entity makes a number of assumptions when determining the acquisition date fair values of intangible assets and property, plant and equipment including:

- Future cash flows which may be influenced by a number of assumptions such as electricity production and selling prices.
- Discount rates.

Why the matter is a key audit matter

We identified the evaluation of the acquisition date fair values of the intangible assets and the property, plant and equipment related to business acquisitions as a key audit matter. This matter represented an area of significant risk of material misstatement given the magnitude of intangible assets and property, plant and equipment. Further, there was a high degree of estimation uncertainty in determining the fair value of the intangible assets and the property, plant and equipment since the discounted cash flow model included significant forward-looking assumptions that could be affected by future economic and market conditions. In addition, significant auditor judgment and specialized skills and knowledge were required in evaluating the results of our audit procedures due to the sensitivity of the Entity's determination of the fair value of intangible assets and property, plant and equipment to minor changes to certain significant assumptions.

How the matter was addressed in the audit

The primary procedures we performed to address this key audit matter included the following:

We evaluated the appropriateness of the future cash flows significant assumptions used by the Entity in its valuation methodologies by:

- Comparing the estimated future electricity production assumption to historical electricity production. We took into account changes in conditions and events affecting the intangible assets and property, plant and equipment to assess the adjustments, or lack of adjustments, made by the Entity in arriving at future electricity production.

- Comparing the future selling price assumption to long-term power purchase agreements and forecasts specific to the regions.

We involved our valuation professionals with specialized skills and knowledge who assisted in:

- Evaluating the appropriateness of discount rates by comparing inputs into the discount rate to publicly available market data for comparable entities.
- Evaluating the appropriateness of the valuation models used by the Entity to calculate the fair value of intangible assets and property, plant and equipment based on the knowledge of the valuation professional.

Evaluation of the impairment analysis for facilities subject to market price risk exposure and for facilities under construction in Hawaii

Description of the matter

We draw attention to Notes 2, 3 and 14 to the financial statements. The Entity has property, plant and equipment of $6,212,371. A portion of these non-financial assets are related to facilities that are subject to market price risk exposure and to facilities under construction in Hawaii.

At the end of each reporting period, the Entity 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 or cash-generating unit ("CGU") is estimated. 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).

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 by the Entity 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.

Future cash flows may be influenced by a number of the Entity's significant assumptions, such as discount rates and:

- For facilities subject to market price risk exposure: selling prices.
- For facilities under construction in Hawaii: timing and costs to complete the construction and renegotiation of selling prices.

Why the matter is a key audit matter

We identified the evaluation of impairment analysis for facilities subject to market price risk exposure and facilities under construction in Hawaii as a key audit matter. This matter represented an area of significant risk of material misstatement given the magnitude of such non-financial assets and the high degree of estimation uncertainty in determining the recoverable amount of such non-financial assets. In addition, significant auditor judgement and specialized skills and knowledge were required in evaluating the results of our audit procedures due to the sensitivity of the Entity's determination of recoverable amount to minor changes to significant assumptions.

How the matter was addressed in the audit

The primary procedures we performed to address this key audit matter included the following:

- For facilities subject to market price risk exposure, we evaluated the appropriateness of the Entity's future selling price assumptions by comparing to forecasts specific to the regions.
- For facilities under construction in Hawaii, we evaluated the appropriateness of the Entity's significant assumptions:
    - for revised timing and costs to complete the construction of the facilities in Hawaii by examining source documentation for a selection of expected costs and by inquiring of project managers to evaluate progress to date and factors impacting the amount of time and costs to complete the project;
    - for renegotiation of selling prices by inspecting correspondence between the Entity and the customer.

We involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the appropriateness of the Entity's discount rates assumptions by comparing the inputs into the discount rates to publicly available market data for comparable entities.

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 a document likely to be entitled "2022 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 the 2022 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 "2022 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 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.

- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

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

KPMG LLP*

Montréal, Canada
February 22, 2023

*CPA auditor, public accountancy permit No. A109612

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

	Notes	Year ended December 31 2022	2021
Revenues		870,494	747,208
Expenses			
Operating	5	207,768	149,106
General and administrative	5	53,071	45,098
Prospective projects	5	24,740	27,367
Earnings before the following:		584,915	525,637
Depreciation and amortization	14, 15	336,053	255,640
Impairment of long-term assets	8, 14, 16, 18	47,868	36,986
Earnings before the following:		200,994	233,011
Finance costs	6	317,842	252,255
Other net income	7	(68,919)	(89,621)
Share of (earnings) losses of joint ventures and associates:			
Share of (earnings) losses, before impairment charges	8	(14,382)	77,280
Share of impairment charges	8	—	112,609
Change in fair value of financial instruments	9 b)	64,145	92,122
Loss before income tax		(97,692)	(211,634)
Recovery of income tax	10	(6,577)	(26,240)
Net loss		(91,115)	(185,394)
(Net loss) earnings attributable to:			
Owners of the parent		(81,619)	(191,805)
Non-controlling interests	25	(9,496)	6,411
		(91,115)	(185,394)
Loss per share attributable to owners:			
Basic net loss per share ($)	11	(0.43)	(1.09)
Diluted net loss per share ($)	11	(0.43)	(1.09)

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Notes	Year ended December 31 2022	2021
Net loss		(91,115)	(185,394)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:			
Foreign currency translation differences for foreign operations	23	97,131	778
Change in fair value of financial instruments designated as net investment hedges	9, 23	(3,484)	7,773
Change in fair value of financial instruments designated as cash flow hedges	9, 23	220,511	78,652
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges	8, 23	9,683	5,303
Related deferred income tax	23	(56,598)	(23,277)
Other comprehensive income		267,243	69,229
Total comprehensive income (loss)		176,128	(116,165)
Total comprehensive income (loss) attributable to:			
Owners of the parent		159,372	(130,733)
Non-controlling interests		16,756	14,568
		176,128	(116,165)

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	December 31, 2022	December 31, 2021
ASSETS			
Current assets			
Cash and cash equivalents		162,971	166,266
Restricted cash	12	54,670	61,659
Accounts receivable	13	179,299	117,906
Derivative financial instruments	9	33,833	17,024
Investment tax credits recoverable	14	1,282	1,200
Prepaid and other		35,887	24,622
Assets held for sale	14	59,217	—
Total current assets		527,159	388,677
Non-current assets			
Property, plant and equipment	14	6,212,371	5,513,392
Intangible assets	15	1,268,960	1,043,994
Project development costs	16	41,151	70,829
Investments in joint ventures and associates	8	135,786	133,398
Derivative financial instruments	9	92,504	39,917
Deferred tax assets	10	68,785	50,484
Goodwill	17	139,676	60,858
Other long-term assets	18	116,035	94,519
Total non-current assets		8,075,268	7,007,391
Total assets		8,602,427	7,396,068
LIABILITIES			
Current liabilities			
Accounts payable and other payables	19	248,659	174,364
Derivative financial instruments	9	22,018	41,315
Current portion of long-term loans and borrowings and other liabilities	20, 21	380,147	517,848
Total current liabilities		650,824	733,527
Non-current liabilities			
Derivative financial instruments	9	79,069	75,064
Long-term loans and borrowings	20	5,384,813	4,411,239
Other liabilities	21	463,863	414,343
Deferred tax liabilities	10	537,431	401,215
Total non-current liabilities		6,465,176	5,301,861
Total liabilities		7,116,000	6,035,388
SHAREHOLDERS' EQUITY			
Equity attributable to owners		1,316,195	1,093,112
Non-controlling interests	25	170,232	267,568
Total shareholders’ equity		1,486,427	1,360,680
Total liabilities and shareholders’ equity		8,602,427	7,396,068

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the year ended December 31, 2022	Equity attributable to owners							Non-controlling interests	Total shareholders' equity
	Common share capital account	Contributed surplus	Preferred shares	Convertible debentures	Deficit	Accumulated other comprehensive loss	Total		
Balance January 1, 2022	360,936	2,022,540	131,069	2,819	(1,373,628)	(50,624)	1,093,112	267,568	1,360,680
Net loss	—	—	—	—	(81,619)	—	(81,619)	(9,496)	(91,115)
Other comprehensive income	—	—	—	—	—	240,991	240,991	26,252	267,243
Total comprehensive (loss) income	—	—	—	—	(81,619)	240,991	159,372	16,756	176,128
Common shares issued on public offering (Note 22)	172,506	—	—	—	—	—	172,506	—	172,506
Common shares issued on private placement (Note 22)	37,275	—	—	—	—	—	37,275	—	37,275
Issuance fees (net of $1,978 of deferred income tax)	(5,432)	—	—	—	—	—	(5,432)	—	(5,432)
Common shares issued through dividend reinvestment plan	1,301	—	—	—	—	—	1,301	—	1,301
Reduction of capital on common shares (Note 22)	(560,532)	560,532	—	—	—	—	—	—	—
Buyback of common shares	(4,417)	—	—	—	—	—	(4,417)	—	(4,417)
Share-based payments and Performance Share Plan	—	2,598	—	—	—	—	2,598	—	2,598
Shares vested - Performance Share Plan	2,114	(4,883)	—	—	—	—	(2,769)	—	(2,769)
Shares purchased - Performance Share Plan	(3,266)	386	—	—	—	—	(2,880)	—	(2,880)
Buyback of non-controlling interests (net of $17,100 of deferred income tax) (Note 4 c)	—	—	—	—	11,815	6,303	18,118	(65,400)	(47,282)
Dividends declared on common shares (Note 22)	—	—	—	—	(146,957)	—	(146,957)	—	(146,957)
Dividends declared on preferred shares (Note 22)	—	—	—	—	(5,632)	—	(5,632)	—	(5,632)
Distributions to non-controlling interests (Note 25)	—	—	—	—	—	—	—	(48,692)	(48,692)
Balance December 31, 2022	485	2,581,173	131,069	2,819	(1,596,021)	196,670	1,316,195	170,232	1,486,427

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Equity attributable to owners								
For the year ended December 31, 2021	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, 2021	4,185	2,026,415	131,069	2,843	(1,043,962)	(111,696)	1,008,854	62,078	1,070,932
Net loss	—	—	—	—	(191,805)	—	(191,805)	6,411	(185,394)
Other comprehensive income	—	—	—	—	—	61,072	61,072	8,157	69,229
Total comprehensive (loss) income	—	—	—	—	(191,805)	61,072	(130,733)	14,568	(116,165)
Common shares issued on July 9, 2021: upon acquisition	89,437	—	—	—	—	—	89,437	—	89,437
Issuance fees (net of $47 of deferred income tax)	(129)	—	—	—	—	—	(129)	—	(129)
Common shares issued on Sept 3, 2021 : public offering	201,259	—	—	—	—	—	201,259	—	201,259
Issuance fees (net of $2,282 of deferred income tax)	(6,334)	—	—	—	—	—	(6,334)	—	(6,334)
Common shares issued on private placements	75,396	—	—	—	—	—	75,396	—	75,396
Issuance fees (net of $25 of deferred income tax)	(70)	—	—	—	—	—	(70)	—	(70)
Business acquisition	—	—	—	—	—	—	—	8,989	8,989
Common shares issued through dividend reinvestment plan	3,312	—	—	—	—	—	3,312	—	3,312
Buyback of common shares	(9,002)	—	—	—	—	—	(9,002)	—	(9,002)
Share-based payments and Performance Share Plan	—	2,073	—	—	—	—	2,073	—	2,073
Convertible debentures converted into common shares and redemption	2,330	—	—	(24)	—	—	2,306	—	2,306
Shares vested - Performance Share Plan	3,174	(6,320)	—	—	—	—	(3,146)	—	(3,146)
Shares purchased - Performance Share Plan	(2,622)	372	—	—	—	—	(2,250)	—	(2,250)
Investments from non-controlling interests (Note 25)	—	—	—	—	—	—	—	196,704	196,704
Dividends declared on common shares (Note 22)	—	—	—	—	(132,229)	—	(132,229)	—	(132,229)
Dividends declared on preferred shares (Note 22)	—	—	—	—	(5,632)	—	(5,632)	—	(5,632)
Distributions to non-controlling interests (Note 25)	—	—	—	—	—	—	—	(14,771)	(14,771)
Balance December 31, 2021	360,936	2,022,540	131,069	2,819	(1,373,628)	(50,624)	1,093,112	267,568	1,360,680

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Notes	Year ended December 31 2022	2021
OPERATING ACTIVITIES			
Net loss		(91,115)	(185,394)
Items not affecting cash:			
Depreciation and amortization	14, 15	336,053	255,640
Impairment of long-term assets	8, 14, 16	47,868	36,986
Share of (earnings) losses of joint ventures and associates	8	(14,382)	189,889
Unrealized portion of change in fair value of financial instruments	9	141,859	18,502
Production tax credits and tax attributes allocated to tax equity investors	7	(67,182)	(91,275)
Other		91	4,502
Finance costs	6	317,842	252,255
Finance costs paid	24 b)	(228,361)	(189,857)
Distributions received from joint ventures and associates	8	22,028	26,072
Recovery of income tax	10	(6,577)	(26,240)
Income tax paid		(2,730)	(5,870)
Effect of exchange rate fluctuations		(10,633)	1,743
		444,761	286,953
Changes in non-cash operating working capital items	24 a)	(14,518)	(21,455)
		430,243	265,498
FINANCING ACTIVITIES			
Dividends paid on common and preferred shares		(149,193)	(131,411)
Distributions to non-controlling interests		(48,692)	(14,771)
Investments from non-controlling interests		—	196,704
Increase in long-term debt, net of deferred financing costs	24 c)	1,717,541	1,682,752
Repayment of long-term debt	24 c)	(1,509,591)	(1,568,183)
Payment of other liabilities	21	(4,834)	(4,384)
Net proceeds from issuance of common shares		202,371	267,768
Payment for buyback of common shares		(4,417)	(11,252)
Purchase of common shares under the Performance Share Plan		(2,880)	—
Payment of payroll withholding on exercise of stock options and Performance Share Plan		(2,769)	(3,146)
		197,536	414,077
INVESTING ACTIVITIES			
Business acquisitions, net of cash acquired	4	(418,044)	(387,434)
Change in restricted cash		9,256	7,886
Additions to property, plant and equipment, net		(119,189)	(250,621)
Additions to intangible assets		(2,508)	—
Additions to project development costs		(29,632)	(38,554)
Investments in joint ventures and associates		(325)	—
Buyback of non-controlling interests	4	(64,382)	—
Change in other long-term assets		(10,942)	1,669
		(635,766)	(667,054)
Effects of exchange rate changes on cash and cash equivalents		4,692	(7,720)
Net change in cash and cash equivalents		(3,295)	4,801
Cash and cash equivalents, beginning of period		166,266	161,465
Cash and cash equivalents, end of period		162,971	166,266

Additional information is presented in Note 24.
The accompanying notes are an integral part of these audited consolidated financial statements.

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 and energy storage 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 22, 2023.

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 that are measured at fair value. 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
Upper Lillooet 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 Europe (2015) Limited Partnership, and its subsidiaries	Own and operate wind facilities	Canada/Europe	100.00%
Innergex Cartier Energy LP	Own and operate wind facilities	Canada	100.00%
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%
Mesgi'g Ugju's'n (MU) Wind Farm L.P.[1]	Own and operate a wind facility	Canada	50.00%
Mountain Air Alternatives LLC, and its subsidiaries	Own and operate wind facilities	United States	100.00%
Foard City Holdings, LLC	Own and operate a wind facility	United States	100.00%
Phoebe Energy Project, LLC	Own and operate a solar facility	United States	100.00%
Hillcrest Solar I, LLC	Own and operate a solar facility	United States	100.00%
Griffin Trail Wind, LLC	Own and operate a wind facility	United States	100.00%
Innergex HQI USA LLC[1]	Own and operate hydroelectric facilities	United States	50.00%
Duqueco SpA	Own and operate hydroelectric facilities	Chile	100.00%
Aela Generación S.A., and its subsidiaries	Own and operate wind facilities	Chile	100.00%

1. Based on the terms of agreements under which these entities were established, the Corporation is exposed to, and has right to, variable returns from its involvement with the investee, and has the current ability to direct these entities's activities that most significantly affect the returns.

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 in the consolidated statement of financial position. Any negative goodwill is recognized directly in the consolidated statements of earnings (loss).

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 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 30 years
Solar facilities	15 to 35 years
Other equipments	3 to 20 years

Leases

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

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 are 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 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, and prepaid royalty fees, reserves, long-term receivables and long-term investments that are not investments in joint ventures and associates.

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 or wind conditions as well as 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 the 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.

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 discount 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.

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, investment tax credits recoverable 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 its tax equity liabilities as liabilities measured at amortized cost.

Tax equity liabilities

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. Subsequent to the Flip Point, the Corporation receives the majority of the project's taxable earnings and renewable tax incentives.

When a tax equity partnership is formed, the Corporation assesses whether the project company should be consolidated based on the Corporation's right to variable returns and its ability to influence financial and operational decisions impacting those returns. Due to the operational and financial nature of the projects, and the protective nature of the rights normally given to tax equity investors, the Corporation typically has the influence to consolidate the entity.

The terms of the tax equity partner's contribution are evaluated to determine the accounting treatment. The contribution generally has the characteristics of a liability as the initial contribution is repaid, including an agreed upon return, and the partner does not share in the risks of the project in the same way as a shareholder. As such, the contribution is accounted for as loans and borrowings on the consolidated statements of financial position and measured at amortized cost until the Flip date of the project. 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 ("PTC")	Allocation of PTCs to the tax equity investor derived from the power generated during the period and recognized in other net income as earned and as a reduction in tax equity financing
Investment tax credits ("ITC")	Allocation of ITCs to the tax equity investor stemming from the construction activities and recognized as a reduction in both the cost of the assets to which they relate and the tax equity financing
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 net income as earned and as a reduction in tax equity financing
Interest expense	Interest expense using the effective interest rate method recognized in finance costs as incurred and as an increase in tax equity financing
Pay-go contributions	Additional cash contributions made by the tax equity investor when the annual production exceeds the contractually determined threshold, as an increase in tax equity financing
Cash distributions	Cash allocation to the tax equity investor, recognized as a reduction in tax equity financing

Subsequent to the Flip Point, the tax equity partner will share in the risks and rewards in the project as a shareholder and will be accounted for as a non-controlling interest.

(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 statements of earnings (loss) 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 (loss) as part of the profit or loss on disposal.

Embedded derivatives

Derivatives embedded in non-derivative financial liabilities or non-financial 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. Derivatives embedded in non-derivative financial assets are not bifurcated.

Non-controlling interests

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

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 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.

Current United States tax law allows wind energy projects to receive production tax credits that are earned for each MWh of generation during the first 10 years of the projects' operation, which are recognized in other net income.

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.

Equity-settled share-based payment

Stock option plan

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

Performance share plan (“PSP”)

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, based on the Corporation's estimate of the number of performance share rights that will eventually vest. It is the Corporation's practice to have the fiduciary purchase that same number of shares on the secondary market at the grant date. The corresponding fair value is debited to common shares capital. The share-based payment expense is subsequently recognized over the vesting period with a corresponding amount to contributed surplus. For shares that are forfeited before vesting, the expense that had previously been recognized is reversed. 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.

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's 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 of Directors 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 foreign exchange forwards to hedge its investment in its Euro functional currency foreign operations. Translation gains or losses on the portion of the 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 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 Euro functional currency 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, 2022	December 31, 2021	2022	2021
Euro	1.4458	1.4391	1.3696	1.4336
US dollar	1.3544	1.2678	1.3013	1.2570

Income taxes

Current and deferred income taxes are recognized in earnings except to the extent that they relate 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 share 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 stock options, if dilutive. The number of additional shares is calculated by assuming that convertible debentures were converted and that outstanding stock options were exercised and that the proceeds from such exercises were used to acquire shares at the average market price during the year.

Changes in accounting policies

On January 1, 2022, the Corporation adopted the following new standards and interpretations which did not have an impact on these consolidated financial statements:

Amendments to IAS 16, Property, Plant and Equipment - Proceeds before Intended Use

On May 14, 2020, the IASB issued *Property, Plant and Equipment — Proceeds before Intended Use* (Amendments to IAS 16). The amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. The amendments are effective for annual reporting periods commencing on or after January 1, 2022. The Corporation adopted the amendments on January 1, 2022, with no impact to the consolidated financial statements.

New accounting standards and interpretations issued but not yet effective

Classification of Liabilities as Current or Non-current (Amendments to IAS 1)

On January 23, 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to clarify the classification of liabilities as current or non-current. On October 31, 2022, the IASB issued Non-current Liabilities with Covenants (Amendments to IAS 1) (the 2022 amendments), to improve the information a company provides about long-term debt with covenants. The 2020 amendments and the 2022 amendments (collectively “the Amendments”) are effective for annual periods beginning on or after January 1, 2024. Early adoption is permitted. The impact for the Corporation is being assessed by management.

Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)

On February 12, 2021, the IASB issued Disclosure Initiative – Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2 Making Materiality Judgements). The key amendments include:

- requiring companies to disclose their material accounting policies rather than their significant accounting policies;
- clarifying that accounting policies related to immaterial transactions, other events or conditions are themselves immaterial and as such do not need to be disclosed
- clarifying that not all accounting policies that relate to material transactions, other events or conditions are themselves material to a company’s financial statements.

The amendments are effective for annual periods beginning on or after January 1, 2023. Early adoption is permitted.

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 determination of control, joint control or significant influence over an investee, fair value determination of the assets acquired and liabilities assumed in business acquisitions, useful lives, impairment of assets, asset retirement obligations, fair value of financial assets and liabilities including derivatives, tax equity financing and effectiveness of hedging relationships. 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

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. In particular, the Corporation exercises judgement in determining whether non-wholly owned subsidiaries are controlled by the Corporation, which involves assessing: (i) how the decisions about the relevant activities of the investee are made; (ii) whether the rights of other co-investors are protective or substantive in nature; and (iii) the Corporation's ability to influence the returns of the investee.

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. The Corporation calculates fair values using appropriate valuation techniques, which are generally based on discounted future cash flows. Future cash flows may be influenced by a number of assumptions 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.

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.

On December 31, 2022, the Corporation revised its useful lives estimates for its wind and solar facilities to 30 and 35 years, respectively, reflecting Management's best estimate, which is supported by our internal expertise in the maintenance of such facilities, as well as independent expert reports on certain facilities and general market observations made in the course of our recent successful and unsuccessful mergers and acquisitions initiatives for similar assets.

Impairment of non-financial assets

The Corporation makes a number of estimates when determining 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 assumptions such as electricity production, duration of the projects, selling prices, costs to operate, capital expenditures, growth rate and the discount rate.

Asset retirement obligations

The Corporation makes a number of estimates when calculating 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.

Financial instruments measured at fair value

In measuring financial instruments at fair value, the Corporation makes estimates and assumptions, including estimates and assumptions about forward electricity prices, interest rates, credit spreads and exchange rates. See Note 27 – Financial Risk Management and Fair Value Disclosures for further details.

Tax equity financing

When a tax equity partnership is formed, the Corporation exercises judgement in assessing whether it retains control over the entity, and in assessing the appropriate classification of the tax equity investor's contribution, which generally bears the characteristics of a liability as the arrangements are made so that the contribution is repaid over time until the tax equity investor has attained an agreed-upon rate of return. Judgment is also exercised in assessing the nature of the tax equity investor's interest after it has attained the agreed-upon rate of return, which generally bears the characteristics of equity as it retains entitlement to a portion of the partnership's variable returns and shares a residual interest in the net assets of the partnership.

Tax equity investors generally require a specified allocation of the project's cash distributions and tax attributes such as production tax credits, investment tax credits and taxable income or loss, including accelerated tax depreciation. Estimates are made when determining the amount and allocation of cash distributions and tax attributes to the tax equity investors, which may be influenced by a number of assumptions such as electricity production, selling prices, costs to operate and tax amounts.

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.

Specifically, the Corporation may, from time to time, enter into long-term power hedge agreements. 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 statements of earnings (loss).

4. BUSINESS ACQUISITIONS

a. Acquisition of Aela

Innergex acquired on June 9, 2022 all of the ordinary shares of Aela Generación S.A. and Aela Energía SpA (together "Aela"), a 332 MW portfolio of three operating wind assets in Chile, for a total cash consideration of US$324,348 ($408,160).

The Aela's portfolio consists of the Sarco wind farm (170 MW), the Aurora wind farm (129 MW) and the Cuel wind farm (33 MW). Revenues from these facilities are anchored by two power purchase agreements with 25 Chilean distribution companies, maturing at the end of 2036 and 2041, for an average remaining tenor of 16 years. The facilities are expected to produce a long-term average of 954.7 GWh per year.

The following table reflects the preliminary amounts recognized for the assets acquired and liabilities assumed, on a fair value basis, at the acquisition date:

	Acquisition accounting	
	US$	CA$
Cash and cash equivalents	18,088	22,762
Accounts receivable	18,959	23,859
Prepaid and other	5,812	7,313
Property, plant and equipment	493,050	620,453
Intangible assets	225,507	283,778
Derivative financial instruments	5,218	6,567
Goodwill	58,066	73,070
Accounts payable and other payables	(17,511)	(22,034)
Long-term loans and borrowings	(380,235)	(478,488)
Other liabilities	(44,517)	(56,021)
Deferred tax liability	(58,089)	(73,099)
Net assets acquired	324,348	408,160

The acquisition gave rise to transaction costs of $11,587 which were expensed as incurred in other net income in the consolidated statements of earnings (loss).

The goodwill arises from the recognition of deferred tax liabilities. No amount of goodwill is expected to be deductible for tax purposes.

The acquisition was accounted for as a business combination and the results have been included in the consolidated statements of earnings (loss) since the date of the acquisition. The revenues and net loss included in the consolidated statements of earnings (loss) are $40,089 and $56,416, respectively for the 206-day period ended December 31, 2022. Had the acquisition taken place on January 1, 2022, revenues and net loss included in the consolidated statements of earnings (loss) for the period from January 1, 2022 to December 31, 2022 would have been $39,311 and $8,634 higher, respectively.

b. Acquisition of San Andrés SpA

Innergex acquired on January, 28, 2022 the 50.6 MW San Andrés solar farm in Chile ("San Andrés"). The facility, commissioned in 2014, is located in the Atacama Desert in northern Chile. San Andrés was acquired for a total consideration of US$28,372 ($36,068). The facility is expected to produce a gross long-term average of approximately 118.9 GWh per year.

The following table reflects the amounts recognized for the assets acquired and liabilities assumed, on a fair value basis, at the acquisition date:

	Acquisition accounting	
	US$	CA$
Cash and cash equivalents	2,692	3,422
Accounts receivable	499	634
Prepaid and other	526	669
Property, plant and equipment	17,454	22,189
Intangible assets	10,562	13,426
Accounts payable and other payables	(1,000)	(1,271)
Other liabilities	(2,361)	(3,001)
Net assets acquired	28,372	36,068

The acquisition gave rise to transaction costs of $149 which were expensed as incurred in other net income in the consolidated statements of earnings (loss).

The acquisition was accounted for as a business combination and the results have been included in the consolidated statements of earnings (loss) since the date of the acquisition. The revenues and net earnings included in the consolidated statements of earnings (loss) are $7,805 and $2,262, respectively for the 336-day period ended December 31, 2022. Had the acquisition taken place on January 1, 2022, revenues and net earnings included in the consolidated statements of earnings (loss) for the period from January 1, 2022 to December 31, 2022 would have been $501 higher and $449 lower, respectively.

c. Purchase of Non-Controlling Interests

Innergex Europe (2015) Limited Partnership

Innergex acquired on October 4, 2022 the remaining 30.45% interests in its Innergex Europe (2015) Limited Partnership subsidiary and its wind portfolio of 16 assets in France for a total consideration of $96,350. The acquisition also settles the outstanding Innergex Europe debentures and all previously accrued and unpaid interest thereon, with an aggregate carrying value of $101,272, resulting in a $4,922 gain recognized in other net income.

Mountain Air Alternatives LLC

Innergex acquired on December 14, 2022 all of the outstanding Class A shares, which are entitled to 37.75% of the cash distributions of its Mountain Air Alternatives LLC subsidiary and its wind portfolio of six assets in Idaho for a total consideration of US$47,525 ($64,382).

5. EXPENSES BY NATURE

Operating, general and administrative and prospective projects expenses, as reported in the consolidated statements of earnings (loss), have been grouped by nature of expenses as follows:

	Year ended December 31	
	2022	2021
Operation and maintenance	125,994	85,243
Salaries and benefits	53,585	46,163
Property taxes and royalties	46,229	41,301
Insurance	18,423	13,076
Other expenses	16,176	8,338
Prospective expenses	13,010	17,028
Professional fees	10,686	8,560
Administrative expenses	1,476	1,862
Total of Operating, General and Administrative and Prospective Projects	285,579	221,571

6. FINANCE COSTS

	Year ended December 31	
	2022	2021
Interest expense on long-term corporate and project loans	216,945	176,945
Interest expense on tax equity financing	30,700	27,020
Inflation compensation interest	18,834	12,504
Amortization of financing fees	15,255	8,308
Interest expense on convertible debentures	13,637	13,642
Interest on lease liabilities	7,612	4,371
Accretion of long-term loans and borrowings and other liabilities	7,482	5,823
Other	9,400	4,275
Interest income on preferred shares of equity-accounted investees	(2,023)	(633)
	317,842	252,255

7. OTHER NET INCOME

	Year ended December 31	
	2022	2021
Production tax credits income	(64,729)	(47,985)
Gain on foreign exchange	(13,848)	(2,331)
(Gain) loss on repayment of loans	(4,922)	1,317
Interest revenues	(3,167)	(438)
Tax attributes allocated to tax equity investors income	(2,453)	(43,290)
Acquisition, integration and restructuring costs	17,918	4,563
Other income, net	2,282	(1,457)
	(68,919)	(89,621)

8. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

8.1 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, 2022	December 31, 2021
Toba Montrose	Own and operate two hydroelectric facilities	British Columbia	40 %	40 %
Dokie	Own and operate a wind facility	British Columbia	25.5 %	25.5 %
Jimmie Creek [1]	Own and operate a hydroelectric facility	British Columbia	50.99 %	50.99 %
Shannon [2]	Own and operate a wind facility	Texas	— %	50 %
Umbata Falls	Own and operate a hydroelectric facility	Ontario	49 %	49 %
Viger-Denonville	Own and operate a wind facility	Quebec	50 %	50 %
Innavik	Develop and construct a hydroelectric facility	Quebec	50 %	50 %

1. The Corporation does not consolidate these entities as it does not control the decision making.
2. On March 4, 2022, the Corporation disposed of its ownership interests in Shannon.

Disposition of Shannon

On March 4, 2022, the Corporation completed the sale of its 50% interest in Shannon for a nominal amount.

8.2 Commitments of joint ventures and associates

As at December 31, 2022, the Corporation's share of the expected 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	2,952	15,486	38,005	56,443

Summary Statements of Earnings (Loss) and Comprehensive Income (Loss)

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.

	Year ended December 31, 2022					
	Toba Montrose	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Total
Revenues	67,565	40,491	24,940	9,355	11,764	154,115
Operating, general and administrative expenses	16,927	10,697	3,934	2,036	2,631	36,225
	50,638	29,794	21,006	7,319	9,133	117,890
Finance costs	22,362	6,043	9,228	2,466	2,716	42,815
Other net income	(314)	(224)	(182)	(50)	(83)	(853)
Depreciation and amortization	19,474	14,035	4,159	4,027	2,675	44,370
Change in fair value of financial instruments	(33)	—	—	(3,199)	(600)	(3,832)
Net earnings	9,149	9,940	7,801	4,075	4,425	35,390
Other comprehensive income	20,544	—	—	—	2,931	23,475
Total comprehensive income	29,693	9,940	7,801	4,075	7,356	58,865
Net earnings attributable to Innergex	3,660	2,535	3,979	1,996	2,212	14,382
Other comprehensive income attributable to Innergex	8,218	—	—	—	1,465	9,683
Total	11,878	2,535	3,979	1,996	3,677	24,065

	Year ended December 31, 2021								
	Energía Llaima (189-day period)	Toba Montrose	Shannon (90-day period)	Flat Top (90-day period)	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Total
Revenues	14,123	72,287	68,908	20,271	40,809	23,457	5,921	10,583	256,359
Operating, general and administrative expenses	5,828	16,399	2,770	2,174	9,369	3,620	2,012	1,236	43,408
	8,295	55,888	66,138	18,097	31,440	19,837	3,909	9,347	212,951
Finance costs	3,248	22,887	3,459	3,734	6,367	9,302	2,434	2,890	54,321
Production tax credits	—	—	(5,533)	(6,406)	—	—	—	—	(11,939)
Tax attributes allocated to tax equity investors	—	—	745	186	—	—	—	—	931
Other net expenses (income)	760	(98)	506	448	(725)	17	96	43	1,047
Depreciation and amortization	6,064	19,852	3,257	3,628	14,031	4,289	4,003	2,751	57,875
Impairment of property, plant and equipment	—	—	117,702	105,408	—	—	—	—	223,110
Unrealized portion of change in fair value of financial instruments	—	697	—	—	—	—	(2,755)	(629)	(2,687)
Realized portion of change in fair value of financial instruments	—	—	114,615	143,380	—	—	—	—	257,995
Income tax recovery	(145)	—	—	—	—	—	—	—	(145)
Net (loss) earnings	(1,632)	12,550	(168,613)	(232,281)	11,767	6,229	131	4,292	(367,557)
Other comprehensive income	—	10,872	—	—	—	—	—	1,909	12,781
Total comprehensive (loss) income	(1,632)	23,422	(168,613)	(232,281)	11,767	6,229	131	6,201	(354,776)
Net (loss) earnings attributable to Innergex	(522)	5,018	(84,306)	(118,463)	3,000	3,176	65	2,143	(189,889)
Other comprehensive income attributable to Innergex	—	4,348	—	—	—	—	—	955	5,303
Total	(522)	9,366	(84,306)	(118,463)	3,000	3,176	65	3,098	(184,586)

1.For the 189-day period ended July 8, 2021, net loss attributable to the owners of Energía Llaima was $1,043 and net loss attributable to non-controlling interests was $589. The Corporation acquired the remaining 50% interest in Energía Llaima on July 9, 2021.

Summary Statements of Financial Position

	As at December 31, 2022					
	Toba Montrose	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Innavik
Current assets	38,724	19,625	5,706	2,741	4,313	5,133
Non-current assets	673,101	186,017	214,853	39,855	45,590	148,536
	711,825	205,642	220,559	42,596	49,903	153,669
Current liabilities	20,159	11,772	6,000	4,960	4,543	34,034
Non-current liabilities	498,215	113,137	162,195	25,130	36,836	125,581
Partner's equity interest (deficit)	193,451	80,733	52,364	12,506	8,524	(5,946)
	711,825	205,642	220,559	42,596	49,903	153,669

	As at December 31, 2021					
	Toba Montrose	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Innavik
Current assets	31,338	14,767	9,995	1,300	3,810	15,963
Non-current assets	691,581	199,962	219,012	44,912	48,276	101,631
	722,919	214,729	229,007	46,212	52,086	117,594
Current liabilities	418,462	112,269	169,279	5,663	5,640	20,607
Non-current liabilities	120,700	15,456	165	30,316	42,680	102,888
Partner's equity (deficit) interest	183,757	87,004	59,563	10,233	3,766	(5,901)
	722,919	214,729	229,007	46,212	52,086	117,594

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, 2022						
	Toba Montrose	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Others	Total
Balance January 1, 2022	73,499	22,246	30,393	5,015	1,879	366	133,398
Increase in investment	—	—	—	—	—	325	325
Share of earnings (loss)	3,660	2,535	3,979	1,996	2,212	—	14,382
Share of other comprehensive income	8,218	—	—	—	1,465	—	9,683
Foreign currency translation differences	—	—	—	—	—	26	26
Distributions received	(8,000)	(4,195)	(7,650)	(883)	(1,300)	—	(22,028)
Balance December 31, 2022	77,377	20,586	26,722	6,128	4,256	717	135,786

	For the year ended December 31, 2021									
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Others	Total
Balance January 1, 2021	108,977	72,533	84,490	118,651	23,900	32,572	4,950	381	383	446,837
Business disposal	(94,013)	—	—	—	—	—	—	—	—	(94,013)
Share of (loss) earnings	(522)	5,018	(84,306)	(118,463)	3,000	3,176	65	2,143	—	(189,889)
Share of other comprehensive income	—	4,348	—	—	—	—	—	955	—	5,303
Impairment of equity accounted investment	(6,314)	—	—	—	—	—	—	—	—	(6,314)
Foreign currency translation differences	(2,065)	—	(184)	(188)	—	—	—	—	(17)	(2,454)
Distributions received	(6,063)	(8,400)	—	—	(4,654)	(5,355)	—	(1,600)	—	(26,072)
Balance December 31, 2021	—	73,499	—	—	22,246	30,393	5,015	1,879	366	133,398

9. DERIVATIVE FINANCIAL INSTRUMENTS

a) Financial position

The following table shows a reconciliation from the opening balances to the closing balances for the derivative financial instruments :

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging derivatives (Level 2)	Power hedges (Level 3)	Currency translation of intragroup loans[1]	Total
As at January 1, 2022	2,485	(78,482)	16,559	—	(59,438)
Business acquisitions (Note 4)	—	6,567	—	—	6,567
Unrealized portion of change in fair value recognized in earnings (loss) [2]	(2,556)	(57,082)	(82,072)	(149)	(141,859)
Change in fair value recognized in other comprehensive income (loss)	(3,484)	223,862	(3,351)	—	217,027
Amortization of accumulated other comprehensive income recognized in revenue	—	—	3,351	—	3,351
Net foreign exchange differences	—	3,273	(3,820)	149	(398)
As at December 31, 2022	(3,555)	98,138	(69,333)	—	25,250

1. Loss from the revaluation, into Canadian dollars, of foreign currency-denominated intragroup loans. On consolidation, although the intragroup loans are eliminated from the consolidated statement of financial position, the foreign subsidiaries' financial positions, including their loan balances towards the Corporation, are converted into Canadian dollars, with currency translation differences being recorded within other comprehensive income (loss), therefore not eliminating the loss recognized in earnings (loss).
2. Refer to Note 9 b) for a reconciliation to the change in fair value recognized in earnings (loss).

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging derivatives (Level 2)	Power hedges (Level 3)	Currency translation of intragroup loans[1]	Total
As at January 1, 2021	(37,113)	(168,002)	54,082	—	(151,033)
Business acquisitions	—	2,738	—	—	2,738
Unrealized portion of change in fair value recognized in earnings (loss) [2]	31,825	3,488	(36,412)	(17,403)	(18,502)
Change in fair value recognized in other comprehensive income (loss)	7,773	81,989	(3,337)	—	86,425
Amortization of accumulated other comprehensive income recognized in revenue	—	—	3,337	—	3,337
Net foreign exchange differences	—	1,305	(1,111)	17,403	17,597
As at December 31, 2021	2,485	(78,482)	16,559	—	(59,438)

b) Change in fair value of financial instruments recognized in the consolidated statements of earnings (loss)

	Year ended December 31	
	2022	2021
Unrealized portion of change in fair value of financial instruments	141,859	18,502
Realized portion of financial instruments:		
Realized gain on the foreign exchange forwards	(43,458)	—
Realized loss on the power hedges	37,479	73,658
Realized (gain) loss on the interest rate swaps	(71,735)	2,508
Realized gain on Phoebe basis hedge	—	(2,546)
Change in fair value of financial instruments	64,145	92,122

10. PROVISION FOR INCOME TAXES

a. Income taxes recognized in the consolidated statements of earnings (loss)

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 the consolidated statements of earnings (loss):

	December 31, 2022	December 31, 2021
Loss before income taxes	(97,692)	(211,634)
Canadian statutory income tax rate	26.6 %	26.6 %
Income tax expense calculated at the statutory rate	(25,986)	(56,295)
Items affecting the statutory rate:		
Non-taxable income	(23,528)	(23,037)
Change in classification of assets held for sale	—	(50,391)
Deferred tax asset not recognized on impairment of investment	—	1,525
Effect of previously unrecognized tax losses balances used in the year	—	(1,501)
Amounts attributable to Tax Equity Investors	12,215	75,444
Change in deferred tax assets not recognized	22,344	13,558
Income taxable at a different rate than the Canadian statutory rate	5,772	11,037
Decrease in deferred income tax rates	(818)	(2,943)
Increase in taxable temporary differences in relation to investments in subsidiaries and in joint ventures	2,248	2,416
Tax on dividends on preferred shares	170	147
Adjustments recognized in the current year in relation to the current tax of prior years	(775)	742
Adjustments recognized in the current year in relation to the deferred tax of prior years	(5,095)	5,082
Income tax on loss (earnings) allocated to minority interests on non-taxable entities	5,131	(4,342)
Others	1,745	2,318
Provision for income taxes recognized in the current year	(6,577)	(26,240)
Current income taxes	483	3,776
Deferred income taxes	(7,060)	(30,016)

The tax rate used for 2022 and 2021 reconciliations above is the average combined corporate tax rate payable by corporate entities in Canada on taxable profits under federal and provincial tax laws.

b. Deferred income tax balances

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

	As at January 1, 2022	Recognized in statement of earnings	Recognized in other comprehensive loss	Acquired in business acquisition	Recognized directly in equity	Net exchange differences	As at December 31, 2022
Deferred income tax assets (liabilities) in relation to:							
Assets held for sale	—	2,947	—	—	—	115	3,062
Property, plant and equipment	(454,644)	(59,245)	—	(27,687)	2,550	(19,082)	(558,108)
Intangible assets	(151,198)	333	—	(77,758)	14,567	(6,846)	(220,902)
Project development costs	30,669	6,861	—	—	—	560	38,090
Investments into subsidiaries and in joint ventures and associates	(68,080)	4,865	(2,608)	—	—	(1,416)	(67,239)
Derivative financial instruments	45,771	39,706	(53,990)	(1,773)	—	(92)	29,622
Long-term loans and borrowings	82	8,936	—	(27,386)	—	(1,765)	(20,133)
Capitalized investment tax credits	23,658	3,327	—	—	—	1,906	28,891
Convertible debentures	(70)	1,683	—	—	—	—	1,613
Other liabilities	6,000	(2,097)	—	4,476	—	423	8,802
Financing fees	(4,837)	(10,011)	—	(2,280)	1,972	(161)	(15,317)
Share-based payment	1,790	(986)	—	—	—	—	804
Disallowed interest carried forward	3,073	1,680	—	—	—	268	5,021
Others	(2,232)	2,257	—	—	—	3	28
	(570,018)	256	(56,598)	(132,408)	19,089	(26,087)	(765,766)
Tax losses carried forward	219,287	6,804	—	59,309	—	11,720	297,120
	(350,731)	7,060	(56,598)	(73,099)	19,089	(14,367)	(468,646)

As at December 31, 2022, the Corporation, its subsidiaries and joint ventures and associates have non-capital losses totaling approximately $1,188 that may be applied against future taxable income. The non-capital losses in Canada and losses incurred before 2018 in the United-States expire gradually between 2023 and 2042. The non-capital losses in France are subject to restrictions over time but have no expiration date.The non-capital losses in Chile and losses incurred after 2017 in United States 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 renewable energy projects currently in operation.

	As at January 1, 2021	Recognized in statement of earnings	Recognized in other comprehensive loss	Acquired in business acquisition	Recognized directly in equity	Net exchange differences	As at December 31, 2021
Deferred income tax assets (liabilities) in relation to:				(Note 33)			
Property, plant and equipment	(349,713)	(112,491)	—	5,630	—	1,930	(454,644)
Intangible assets	(165,727)	8,122	—	—	—	6,407	(151,198)
Project development costs	27,438	3,255	—	—	—	(24)	30,669
Investments into subsidiaries and in joint ventures and associates	(117,827)	50,429	(1,394)	—	—	712	(68,080)
Derivative financial instruments	65,827	2,244	(21,883)	—	—	(417)	45,771
Long-term loans and borrowings	7,232	(7,312)	—	—	—	162	82
Capitalized investment tax credits	12,273	11,363	—	—	—	22	23,658
Convertible debentures	(661)	591	—	—	—	—	(70)
Other liabilities	4,634	1,809	—	(436)	—	(7)	6,000
Financing fees	(5,432)	(1,792)	—	—	2,354	33	(4,837)
Share-based payment	2,563	(773)	—	—	—	—	1,790
Disallowed interest carried forward	1,112	1,949	—	—	—	12	3,073
Others	3	(2,206)	—	—	—	(29)	(2,232)
	(518,278)	(44,812)	(23,277)	5,194	2,354	8,801	(570,018)
Tax losses carried forward	132,852	74,828	—	12,884	—	(1,277)	219,287
	(385,426)	30,016	(23,277)	18,078	2,354	7,524	(350,731)

c. Unrecognized deductible temporary differences, unused tax losses and unused tax credits

	December 31, 2022	December 31, 2021
Non-capital tax losses	318,780	136,853
Capital tax losses	70,562	23,581
Tax credits	25,044	24,117
Transaction costs	477	477
	414,863	185,028

The unrecognized tax losses will expire gradually between 2026 and 2042. The unrecognized tax credits will expire gradually between 2035 and 2042.

11. EARNINGS (LOSS) PER SHARE

Basic	Year ended December 31 2022	2021
Net loss attributable to owners of the parent	(81,619)	(191,805)
Dividends declared on preferred shares	(5,632)	(5,632)
Net loss attributable to common shareholders	(87,251)	(197,437)
Weighted average number of common shares	201,835,956	180,856,774
Basic net loss per share ($)	(0.43)	(1.09)

Diluted	Year ended December 31 2022	2021
Net loss attributable to common shareholders	(87,251)	(197,437)
Diluted weighted average number of common shares	201,835,956	180,856,774
Diluted net loss per share ($)	(0.43)	(1.09)

	Year ended December 31 2022	2021
Instruments that are excluded from the dilutive elements:		
Stock options	284,769	265,570
Shares held in trust related to the Performance Share Plan	592,257	541,261
Convertible debentures	13,604,473	13,604,473
	14,481,499	14,411,304

12. RESTRICTED CASH

As at	December 31, 2022	December 31, 2021
Restricted proceeds account	33,556	35,260
Restricted cash accounts	11,677	17,201
Debt service payment accounts	9,437	9,198
	54,670	61,659

As required under several projects' credit agreements, the Corporation maintains restricted cash accounts and restricted proceeds accounts. The unused portion of loan 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.

13. ACCOUNTS RECEIVABLE

As at	December 31, 2022	December 31, 2021
Trade	124,349	84,246
Dividends receivable on preferred shares	7,875	5,687
Commodity taxes	19,012	4,056
Advances to related parties	6,240	3,678
Income taxes receivable	5,191	4,511
Other	16,632	15,728
	179,299	117,906

14. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facilities	Facilities under construction	Other	Total
Cost							
As at January 1, 2022	185,100	2,594,780	2,891,964	819,621	72,877	45,064	6,609,406
Additions [1]	12,373	5,243	3,520	2,450	142,089	5,601	171,276
Investment tax credits [2]	—	—	—	—	(8,535)	—	(8,535)
Business acquisitions (Note 4)	48,170	—	572,275	22,184		13	642,642
Transfer of assets upon commissioning	—	—	—	—	(6,840)	6,840	—
Transfer from project development costs	—	—	—	—	40,660	—	40,660
Reclassification	—	—	(1,274)	—	(59)	1,333	—
Assets classified as held for sale	—	—	—	—	(59,899)	—	(59,899)
Impairment	—	—	—	—	(25,226)	—	(25,226)
Dispositions	—	(322)	(7,325)	—	—	(390)	(8,037)
Other changes[3]	41,977	293	(52,768)	(15,690)	—	(21)	(26,209)
Net foreign exchange differences	13,474	34,932	105,344	46,872	10,372	1,383	212,377
As at December 31, 2022	301,094	2,634,926	3,511,736	875,437	165,439	59,823	7,548,455
Accumulated depreciation							
As at January 1, 2022	(16,801)	(391,093)	(549,980)	(115,531)	—	(22,609)	(1,096,014)
Depreciation[4]	(7,222)	(53,478)	(128,889)	(32,221)	—	(6,385)	(228,195)
Dispositions	—	37	1,438	—	—	367	1,842
Net foreign exchange differences	(865)	(1,270)	(6,353)	(5,030)	—	(199)	(13,717)
As at December 31, 2022	(24,888)	(445,804)	(683,784)	(152,782)	—	(28,826)	(1,336,084)
Carrying amounts as at December 31, 2022	276,206	2,189,122	2,827,952	722,655	165,439	30,997	6,212,371

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 used for a specific property, plant and equipment. Additions in the current period include $4,055 of capitalized financing costs incurred prior to commissioning.
2. The Corporation accrued for US$6,712 ($8,535) in investment tax credits recoverable in relation to the construction of the Hale Kuawehi solar project, which were recognized as a reduction in the cost of property, plant and equipment. As at December 31, 2022, the current balance of investments tax credits recoverable, on the Hillcrest and the Hale Kuawehi projects, amounts to US$947 ($1,282), while the non current balance amounts to US$6,712 ($9,091).
3. Includes remeasurements of the right-of-use assets and the asset retirement obligations of $41,977 and $(66,594), respectively.
4. An amount of $227 of the depreciation expense for the land leases is capitalized as a construction cost in facilities under construction.

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facilities	Facilities under construction	Other	Total
Cost							
As at January 1, 2021	176,831	2,091,345	2,596,633	516,989	529,484	33,970	5,945,252
Additions	—	5,157	10,552	225	214,715	7,973	238,622
Investment tax credits	—	—	—	—	(14,070)	—	(14,070)
Business acquisitions	22,983	491,704	—	10,039	—	712	525,438
Transfer of assets upon commissioning	—	—	358,537	291,636	(650,217)	44	—
Transfer from project development costs	—	—	—	—	682	—	682
Reclassification	—	—	—	(644)	104	540	—
Dispositions	—	(2,227)	(2,957)	—	—	(267)	(5,451)
Other changes	(12,050)	9	(7,915)	(2,422)	—	2,273	(20,105)
Net foreign exchange differences	(2,664)	8,792	(62,886)	3,798	(7,821)	(181)	(60,962)
As at December 31, 2021	185,100	2,594,780	2,891,964	819,621	72,877	45,064	6,609,406
Accumulated depreciation							
As at January 1, 2021	(10,482)	(348,109)	(445,896)	(69,382)	—	(18,258)	(892,127)
Depreciation	(6,557)	(43,306)	(114,839)	(21,441)	—	(4,430)	(190,573)
Reclassification	—	—	—	249	—	(249)	—
Dispositions	—	352	332	—	—	298	982
Impairment charge	—	—	—	(24,729)	—	—	(24,729)
Net foreign exchange differences	238	(30)	10,423	(228)	—	30	10,433
As at December 31, 2021	(16,801)	(391,093)	(549,980)	(115,531)	—	(22,609)	(1,096,014)
Carrying amounts as at December 31, 2021	168,299	2,203,687	2,341,984	704,090	72,877	22,455	5,513,392

Disposal of Safe Harbor Solar Modules

The company entered an agreement on December 8, 2022 to dispose of safe harbor solar modules in early 2023 for cash proceeds of US$44,124 ($60,450). An impairment charge of US$8,335 ($11,419) was recorded in 2022 to decrease the carrying amount of the modules to the expected fair value less costs to sell pursuant to the sale of the modules. The decision to sell these modules follows the publication of the Inflation Reduction Act ("IRA") supporting renewable energy projects, allowing Innergex to secure tax incentives for its development project portfolio without the use of the safe harbor modules previously secured under the former tax incentive program.

Impairment of Hale Kuawehi

An impairment charge of US$10,226 ($13,807) was recognized on the Hale Kuhawehi construction project located in Hawaii for which uncertainties exist regarding the timing and costs to complete the construction, the renegotiation of selling prices and the profitability of the project.

Right-of-use assets

Included in property, plant and equipment are right-of-use assets pursuant to lease agreements. Below is a reconciliation of the carrying amounts:

	Land	Hydroelectric facilities	Other	Total
Cost				
As at January 1, 2022	159,139	118	11,147	170,404
Additions	11,453	—	—	11,453
Business acquisition	48,170	—	—	48,170
Other changes	41,977	—	—	41,977
Net foreign exchange differences	11,919	—	184	12,103
As at December 31, 2022	272,658	118	11,331	284,107
Accumulated depreciation				
As at January 1, 2022	(16,800)	(6)	(3,361)	(20,167)
Depreciation	(7,222)	(2)	(1,506)	(8,730)
Net foreign exchange differences	(865)	—	(77)	(942)
As at December 31, 2022	(24,887)	(8)	(4,944)	(29,839)
Carrying amounts as at December 31, 2022	247,771	110	6,387	254,268

	Land	Hydroelectric facilities	Other	Total
Cost				
As at January 1, 2021	173,670	109	9,166	182,945
Business acquisition	445	—	—	445
Dispositions	—	—	(176)	(176)
Other changes	(12,050)	9	2,274	(9,767)
Net foreign exchange differences	(2,926)	—	(117)	(3,043)
As at December 31, 2021	159,139	118	11,147	170,404
Accumulated depreciation				
As at January 1, 2021	(10,482)	(4)	(2,226)	(12,712)
Depreciation	(6,556)	(2)	(1,322)	(7,880)
Dispositions	—	—	176	176
Net foreign exchange differences	238	—	11	249
As at December 31, 2021	(16,800)	(6)	(3,361)	(20,167)
Carrying amounts as at December 31, 2021	142,339	112	7,786	150,237

15. INTANGIBLE ASSETS

	Hydroelectric facilities	Wind farm facilities	Solar facilities	Total
Cost				
As at January 1, 2022	780,422	648,591	14,986	1,443,999
Additions	2,380	128	—	2,508
Business acquisitions (Note 4)	—	283,778	13,426	297,204
Other changes[1]	(16,659)	—	—	(16,659)
Net foreign exchange	14,977	40,200	1,251	56,428
As at December 31, 2022	781,120	972,697	29,663	1,783,480
Accumulated amortization				
As at January 1, 2022	(224,244)	(167,961)	(7,800)	(400,005)
Amortization	(57,450)	(51,340)	705	(108,085)
Net foreign exchange	(2,810)	(3,280)	(340)	(6,430)
As at December 31, 2022	(284,504)	(222,581)	(7,435)	(514,520)
Carrying amounts as at December 31, 2022	496,616	750,116	22,228	1,268,960

1. Includes remeasurements of the future ownership rights of $(16,659).

	Hydroelectric facilities	Wind farm facilities	Solar facilities	Total
Cost				
As at January 1, 2021	575,536	667,832	15,009	1,258,377
Business acquisitions	206,388	—	—	206,388
Other changes	(6,190)	—	—	(6,190)
Net foreign exchange	4,688	(19,241)	(23)	(14,576)
As at December 31, 2021	780,422	648,591	14,986	1,443,999
Accumulated amortization				
As at January 1, 2021	(201,295)	(133,042)	(4,717)	(339,054)
Amortization	(22,892)	(40,847)	(3,047)	(66,786)
Net foreign exchange	(57)	5,928	(36)	5,835
As at December 31, 2021	(224,244)	(167,961)	(7,800)	(400,005)
Carrying amounts as at December 31, 2021	556,178	480,630	7,186	1,043,994

16. PROJECT DEVELOPMENT COSTS

As at	December 31, 2022	December 31, 2021
Beginning of year	70,829	14,092
Business acquisitions	—	16,417
Additions	30,178	40,428
Transfer to property, plant and equipment	(40,660)	(682)
Impairment of project development costs	(22,642)	—
Net foreign exchange	3,446	574
End of year	41,151	70,829

An impairment charge of $22,642 was recognized on development projects located in Hawaii for which uncertainties exist regarding the timing and profitability of these projects. For the year ended December 31, 2021, no impairment charge was recognized.

17. GOODWILL

Allocation of goodwill to each significant CGU or group of CGUs is as follows:

	Hydroelectric facilities	Wind farm facilities	Total
As at January 1, 2022	20,291	40,567	60,858
Business acquisition (Note 4)	—	73,070	73,070
Net foreign exchange	—	5,748	5,748
As at December 31, 2022	20,291	119,385	139,676

	Hydroelectric facilities	Wind farm facilities	Total
As at January 1, 2021	20,291	43,007	63,298
Net foreign exchange	—	(2,440)	(2,440)
As at December 31, 2021	20,291	40,567	60,858

On December 31, 2022, 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 4.20% to 8.50% (4.63% to 8.50% in 2021).

Key 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.
- 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.

18. OTHER LONG-TERM ASSETS

As at	December 31, 2022	December 31, 2021
Hydrology/ wind power reserve [1]	46,434	49,001
Major maintenance reserve	7,333	9,784
Security deposits	7,322	7,391
Investments in preferred shares of equity-accounted investees	15,797	—
Other	39,149	28,343
	116,035	94,519

1.The availability in the reserve accounts is restricted by credit agreements.

19. ACCOUNTS PAYABLE AND OTHER PAYABLES

As at	December 31, 2022	December 31, 2021
Trade and other payables	139,900	71,887
Dividends payable to shareholders	38,152	36,048
Interest payable	28,395	30,906
Construction holdbacks	21,758	18,672
Salaries and benefits	10,304	7,814
Commodity taxes	8,269	5,318
Income taxes payable	1,881	3,719
	248,659	174,364

20. LONG-TERM LOANS AND BORROWINGS

	Currency	Interest rates	Maturity	December 31, 2022	December 31, 2021
Corporate indebtedness					
Revolving term credit facility	CAD/USD	3.34%-6.18%	2027	718,232	398,758
Subordinated unsecured term loan	CAD	5.13 %	2023	150,000	150,000
Alterra loans	CAD	5.01%-5.10%	2028-2031	155,000	145,000
				1,023,232	693,758
Convertible debentures					
4.65% Convertible Debentures[3]	CAD	4.65 %	2026	138,028	136,985
4.75% Convertible Debentures[4]	CAD	4.75 %	2025	144,650	143,273
				282,678	280,258
Tax equity financing[1,2]					
Wind segment					
Foard City	USD	7.50 %	2029[5]	238,734	240,696
Griffin Trail	USD	6.80 %	2031[5]	160,349	166,257
Solar Segment					
Hillcrest	USD	5.15 %	2028[5]	23,274	25,063
Phoebe	USD	7.14 %	2026[5]	19,940	23,080
Others	USD	8.00 %	2023	850	871
				443,147	455,967
Project-level indebtedness					
Chile green bonds (c)	USD	6.28 %	2036	887,572	—
Hydroelectric segment					
Boulder Creek and Upper Lillooet	CAD	4.22%-4.46%	2042-2056	487,307	487,490
Harrison Operating Facilities	CAD	4.07%-5.88%	2049	450,279	442,474
Big Silver Creek	CAD	4.57%-4.76%	2041-2056	193,501	193,501
Kwoiek Creek	CAD	5.08%-10.07%	2052-2054	161,501	163,520
Tretheway Creek	CAD	4.99 %	2055	91,957	91,999
Ashlu Creek	CAD	6.18%-6.93%	2025	73,414	77,051
Northwest Stave River	CAD	5.30 %	2053	71,065	71,094
Sainte-Marguerite	CAD	7.40%-8.00%	2025-2064	51,760	55,080
Magpie	CAD	6.36%-15.50%	2025-2031	36,767	40,091
Rutherford Creek	CAD	6.88 %	2024	8,714	14,045
Fitzsimmons Creek	CAD	4.70%-5.16%	2026	17,805	18,311
Duqueco	USD	3.65 %	2022	—	141,798
Licán	USD	3.26 %	2022	—	32,963
Guayacán	USD	4.91%-9.03%	2032	11,875	11,601
Others	USD	7.17 %	2023	5,345	9,598
Wind segment					
Innergex Cartier Energie	CAD	4.33%-6.44%	2032	402,965	446,555
Mesgi'g Ugju's'n	CAD	3.54%-4.28%	2026-2036	209,929	223,113
Innergex Europe (d), Note 4 c))	CAD	8.00 %	2022	—	77,957
Yonne and Yonne II	EURO	1.30%-1.65%	2031-2039	88,229	95,236
Rougemont 2	EURO	2.85%-4.30%	2035	64,556	69,242
Vaite	EURO	2.83%-4.30%	2035	57,939	62,476
Rougemont 1	EURO	2.85%-4.30%	2035	56,420	60,585
Plan Fleury	EURO	1.65 %	2032-2034	36,869	40,491
Les Renardières	EURO	1.70 %	2032-2034	32,431	35,672
Beaumont	EURO	2.42%-3.78%	2027-2031	20,943	23,509

(continued)	Currency	Interest rates	Maturity	December 31, 2022	December 31, 2021
Montjean	EURO	1.15%-2.73%	2026-2031	15,812	17,746
Theil Rabier	EURO	1.15%-2.73%	2026-2031	15,812	17,746
Foard City	USD	3.82%-4.18%	2026	18,165	20,741
Mountain Air	USD	2.03%-6.00%	2029-2032	153,282	151,350
Others	EURO	1.66%-4.75 %	2024-2030	46,645	54,178
Solar segment					
Hillcrest	USD	2.70 %	2028	89,363	89,214
Phoebe	USD	5.07%-8.73%	2026	136,591	132,161
Stardale	CAD	5.10%-6.44%	2032	72,934	75,256
Hale Kuawehi (b)	USD	5.81 %	2023	4,897	—
Pampa Elvira	USD	2.89 %	2022	—	2,828
Others	USD	5.35%-5.81%	2024-2026	15,812	15,708
				4,088,456	3,562,380
Total long-term loans and borrowings				5,837,513	4,992,363
Deferred financing costs				(78,303)	(67,928)
				5,759,210	4,924,435
Current portion of long-term loans and borrowings				(374,397)	(513,196)
Long-term loans and borrowings				5,384,813	4,411,239

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 driven by the dates on which the tax equity investor reaches the agreed upon target rate of return.
3. The 4.65% Convertible Debentures are convertible at the holder’s option into common shares of the Corporation at a conversion price of $22.90 per share.
4. The 4.75% Convertible Debentures are convertible at the holder’s option into common shares of the Corporation at a conversion price of $20.00 per share.
5. Represents the expected Flip Point date as estimated at the date of final funding from the tax equity investor. Actual Flip Point may differ, subject to the facilities' respective operating performance.

The carrying amount of assets pledged to secure the loans totalled $5,792,466 ($5,044,788 in 2021).

Letters of credit under revolving term credit facility and project loans amount to $302,059 ($207,147 in 2021).

Tax equity investors in U.S. wind projects generally require sponsor guarantees as a condition to their investment. To support the tax equity investments, the Corporation executed guarantees 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.

As at December 31, 2022, the Corporation and its subsidiaries have met all material financial and non-financial conditions related to their credit agreements.

a. Corporate Indebtedness

Revolving Term Credit Facility

The Corporation has access to a revolving term credit facility maturing in 2027. The available facility amount is $950,000. 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, SOFR or EURIBOR plus a spread which depends on interest coverage ratio and leverage ratio. As of December 31, 2022, an amount of $56,891 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 $150,000 guaranteed by Export Development Canada. As of December 31, 2022, letters of credit have been issued for an amount of $45,672.

Subordinated Unsecured Term Loan

The Corporation has a subordinated unsecured term loan maturing in 2023 and repayable in full at maturity. The Corporation reclassified the $150,000 subordinated unsecured term loan as current, following the upcoming maturity on February 1, 2023.

On February 1, 2023, Innergex has completed the refinancing of the subordinated unsecured term loan with a non-revolving term credit facility of $75,000 bearing interest at a fixed rate of 6.25% and maturing on February 1, 2025, and a non-revolving term credit facility of $75,000 bearing interest at a variable rate of 4.87%, based on the bankers' acceptance rates plus a spread of 1.85% which depends on leverage ratio, maturing on February 1, 2025. Concurrently, the Corporation concluded an interest rate swap to hedge a $50,000 portion of the credit facility notional that is subject to variable interest rates.

b. Financing of the Hale Kuawehi project

On March 16, 2022, the Corporation entered into a financing agreement for the construction of the Hale Kuawehi solar and battery storage project in Hawaii consisting of a US$54,543 construction loan bearing interest at 1-month SOFR + 1.375% maturing in 2023, and a US$61,630 tax equity bridge loan bearing interest at 1-month SOFR + 0.75% maturing in 2023.

c. Aela Acquisition and Refinancing of the Chilean project debts

As part of the Aela Acquisition, the Corporation assumed the facilities non-recourse debt, with an outstanding principal balance of US$380,235 ($478,488) at acquisition date, bearing interest at Libor 180 days + 2.70%, and payable semi-annually in February and August. The non-recourse debt matures on February 15, 2035.

Subsequently, on August 5, 2022, the Corporation completed, through its Aela Generación subsidiary, the US$803,116 ($1,032,326) refinancing of the non-recourse debt of its portfolio of wholly owned assets in Chile, comprised of the Aela, Duqueco and Licán loans, with the issuance of US$710,000 ($912,634) senior secured notes (the "Green Bonds") and a US$93,116 ($119,682) letter of credit facility. The Green Bonds bear interest at a hedged rate of 5.54% with semi-annual principal repayments to begin in December 2025 and mature in 2036 (with a balloon payment of US$139,000 ($178,671)).

d. Acquisition of remaining interests in wind portfolio in France

On October 4, 2022, Innergex completed the acquisition of the remaining 30.45% non-controlling interest in its wind portfolio of 16 assets in France and concurrently reimbursed the outstanding debentures for a total consideration of $96,350.

21. OTHER LIABILITIES

	Contingent considerations	Asset retirement obligations	Interest payable on SM S.E.C. debenture	Future ownership rights	Deferred income	Lease liabilities	Total
As at January 1, 2022	11,049	165,808	31,210	35,117	18,702	157,109	418,995
Business acquisitions (Note 4)	—	11,914	—	—	—	47,108	59,022
New obligations	—	—	—	—	—	11,453	11,453
Interest expense included in finance costs	—	—	5,039	—	—	—	5,039
Accretion expense included in finance costs	27	5,748	—	1,242	—	—	7,017
Remeasurement	—	(66,594)	—	(16,659)	—	41,977	(41,276)
Amortization	—	—	—	—	(799)	—	(799)
Payments	(520)	—	—	—	—	(3,515)	(4,035)
Impact of foreign exchange fluctuations	677	1,825	—	—	—	11,695	14,197
As at December 31, 2022	11,233	118,701	36,249	19,700	17,903	265,827	469,613
Current portion of other liabilities	(256)	—	—	—	—	(5,494)	(5,750)
Long-term portion of other liabilities	10,977	118,701	36,249	19,700	17,903	260,333	463,863

	Contingent considerations	Asset retirement obligations	Interest payable on SM S.E.C. debenture	Future ownership rights	Deferred income	Lease liabilities	Total
As at January 1, 2021	1,861	162,625	26,461	40,031	—	172,807	403,785
Business acquisitions	—	1,558	—	—	—	472	2,030
New obligations	9,746	8,447	—	—	19,642	—	37,835
Interest expense included in finance costs	—	—	4,749	—	—	—	4,749
Accretion expense included in finance costs	36	4,167	—	1,276	—	—	5,479
Remeasurement	—	(7,791)	—	(6,190)	—	(9,767)	(23,748)
Amortization					(940)		(940)
Payments	(761)	—	—	—	—	(3,623)	(4,384)
Impact of foreign exchange fluctuations	167	(3,198)	—	—	—	(2,780)	(5,811)
As at December 31, 2021	11,049	165,808	31,210	35,117	18,702	157,109	418,995
Current portion of other liabilities	(515)	—	—	—	—	(4,137)	(4,652)
Long-term portion of other liabilities	10,534	165,808	31,210	35,117	18,702	152,972	414,343

a. 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, after exercising its term renewal options, at least 30 and 35 years, respectively, after the signing date.

The cash flows were discounted at rates between 4.42% and 7.90% as at December 31, 2022 (0.99% to 4.87% in 2021) to determine the obligations.

b. Interest payable on the Sainte-Marguerite debenture

This debenture carries an interest rate of 8.00%; it has no predetermined repayment schedule and matures in 2064. The partner, Régime de Rentes du Mouvement Desjardins, is considered a related party. Unpaid interests are compounded and are recorded in other long-term liabilities.

c. Future ownership rights

Other liabilities include 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.

d. 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.

e. Mesgi'g Ugju's'n letter of credit

During 2021, the Corporation availed itself of the full amount under a $19,642 letter of credit to cover certain unfulfilled performance obligations following the bankruptcy of the service provider under the turbine supply agreement at Mesgi'g' Ugju's'n. The proceeds are subject to restrictions under the Mesgi'g Ugju's'n credit agreement and as such, have been recognized as other long-term assets and the associated obligation as other non-current liabilities. The proceeds are to be used in the future to remediate the unfulfilled performance obligations under the turbine supply agreement.

f. Contigent considerations

On July 9, 2021, Innergex acquired the remaining 50% interest in Energía Llaima SpA (“Energía Llaima”). The purchase price included a contingent consideration evaluated at US$3,650 ($4,575), calculated on the fair value of the lands owned by Inversiones La Frontera Sur SpA and Inversiones San Carlos SpA at the date of acquisition. The contingent consideration is to be paid within five to six years following the closing of the acquisition.

On October 25, 2021, Innergex and HQI US Holding LLC, a subsidiary of Hydro-Québec, acquired the Curtis Palmer hydroelectric portfolio located in Corinth, New York. The purchase price included a contingent consideration provision evaluated at US$3,169 ($3,916), based on the evolution of the New York Independent System Operator ("NYISO") market pricing during calendar years 2023 and 2024, limited to US$30,000.

22. 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").

Issued and outstanding shares

As at	December 31, 2022	December 31, 2021
Number of common shares	204,132,833	192,493,999
Number of Series A Preferred Shares	3,400,000	3,400,000
Number of Series C Preferred Shares	2,000,000	2,000,000

a) Common shares

The change in the number of common shares was as follows:

As at	December 31, 2022	December 31, 2021
Issued and fully paid		
Beginning of the year	192,493,999	174,582,586
Issued upon business acquisitions	—	4,048,215
Issued on public offering	9,718,650	10,374,150
Issued following the Strategic Alliance with Hydro-Québec	2,100,000	3,729,050
Issued through dividend reinvestment plan	73,865	146,621
Conversion of debentures	—	104,569
Buybacks	(253,681)	(491,192)
End of year	204,132,833	192,493,999
Held in trust under the Performance Share Plan		
Beginning of the year	(541,261)	(557,091)
Purchased	(178,597)	(118,562)
Distributed	127,601	134,392
End of year	(592,257)	(541,261)
Common shares outstanding at end of the year	203,540,576	191,952,738

Issuance of common shares

As part of the public offering that closed on February 22, 2022, the Corporation issued 9,718,650 common shares at a price per share of $17.75 for cash proceeds of $172,506. Concurrently with the closing of the public offering, Hydro-Québec subscribed for 2,100,000 common shares of the Corporation for cash proceeds of $37,275.

Buyback of common shares

During the year ended December 31, 2022, 253,681 common shares have been purchased and cancelled under the normal course issuer bid terminated on May 23, 2022, at an average price of $17.40 per share.

New Normal Course issuer Bid

The Corporation received the approval from the Toronto Stock Exchange ("TSX") to renew the normal course issued bid on its common shares and to commence a normal course issuer bid on its Series A preferred shares and Series C preferred shares (the "New Bid"). Under the New Bid, the Corporation could purchase for cancellation up to 4,082,073 of its common shares, representing approximately 2% of the 204,103,658 issued and outstanding common shares of the Corporation as at May 11, 2022. The Corporation could purchase for cancellation up to 68,000 of its Series A preferred shares, representing approximately 2% of the 3,400,000 issued and outstanding Series A preferred shares of the Corporation as at May 11, 2022. The Corporation could purchase for cancellation up to 40,000 of its Series C preferred shares, representing approximately 2% of the 2,000,000 issued and outstanding Series C preferred shares of the Corporation as at May 11, 2022. The New Bid commenced on May 24, 2022 and will terminate on May 23, 2023.

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 10, 2022. This resulted in a decrease of the shareholders' capital account of $560,532 and an equivalent increase of the contributed surplus from reduction of capital on common shares account.

b) Preferred shares

Series A Preferred Shares

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 each year. The annual dividend rate for the five-year period starting January 15, 2021, equals $0.8110 per share.

At its option, each holder of Series A Preferred Shares has the right 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, 2021, and every five years thereafter. In addition, the Corporation has the right to redeem all or any number of the outstanding Series A Preferred Shares on January 15, 2021, and every five years thereafter.

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

The holders of Series C 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 each year at an annual rate equal to $1.4375 per share. The Corporation has the right to redeem all or any number of the outstanding Series C Preferred Shares.

Equity-based compensation

a) Stock option plan

The Corporation has a stock option plan providing for the granting of options by the Board of Directors to employees, officers, directors and certain consultants of the Corporation and its subsidiaries to purchase common shares. Options granted under the stock option plan will have an exercise price of not less than the market price of the common shares at the date of grant of the option, calculated as the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The maximum number of common shares of the Corporation available for issuance pursuant to options granted under the 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 stock option plan cannot at any time exceed 1% of the issued and outstanding common shares. Options must be exercised during a period established by the Board of Directors, which may not be greater than 10 years after the date of grant. Options granted under the stock option plan vest in equal amounts on a yearly basis over a period of four to five years following the grant date.

	December 31, 2022		December 31, 2021	
	Number of options	Weighted average exercise price ($)	Number of options	Weighted average exercise price ($)
Outstanding - beginning of year	265,570	16.83	233,539	15.78
Granted during the year	51,352	17.50	32,031	24.49
Cancelled during the year	(32,153)	18.59	—	—
Outstanding - end of year	284,769	16.75	265,570	16.83
Options exercisable - end of year	186,088	15.55	159,936	15.00

The following options were outstanding as at December 31, 2022:

Year of granting	Number of options outstanding	Exercise price ($)	Number of options exercisable	Year of maturity
2016	56,531	14.65	56,531	2023
2017	54,411	14.52	54,411	2024
2019	63,878	14.41	47,909	2026
2020	41,374	20.52	20,687	2027
2021	26,201	24.49	6,550	2028
2022	42,374	17.50	—	2029
	284,769		186,088	

The weighted average contractual life of the outstanding stock options is five years.

A compensation expense of $35 was recorded during the year ended December 31, 2022 with respect to the stock option plan ($87 in 2021).

Granted
During the year ended December 31, 2022, 51,352 options were granted. The options granted vest in four equal tranches until February 25, 2026 and must be exercised before February 25, 2029 at an exercise price of $17.50.

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, 2022	December 31, 2021
Risk-free interest rate	1.78 %	0.97 %
Expected annual dividend per common share	$ 0.72	$ 0.72
Expected life of options	6	6
Expected volatility	26.77 %	26.03 %

Expected volatility is estimated by considering historic average share price volatility of the Corporation.

b) Performance Share Plan (the "PSP") and Deferred Share Unit Plan (the “DSU”)

Performance Share Plan

The goal of the PSP is to motivate the key employees and officers to create long-term economic value for the Corporation and its shareholders. This portion of the Equity-Based Incentive Plan focuses key employees and officers on delivering business performance over the next three years against the total shareholder value and relative to a peer 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 years thereafter. The fair value of the performance share rights is determined on the grant date, based on the Corporation's estimate of the number of performance share rights that will eventually vest. 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.

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. These shares are held in Trust for the benefit of the beneficiaries until the Performance share rights become vested or cancelled. The cost of these purchases has been deducted from share capital.

Deferred Share Unit Plan

Under the Corporation’s DSU, directors receive a portion of their compensation in DSUs in lieu of cash compensation. Officers may elect to receive all or a portion of their bonus in DSU 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 and the officer's DSU account is credited with additional DSUs equivalent to the dividend paid.

DSUs cannot be redeemed for cash or shares until the director or the officer leaves the Corporation. 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.

Summary

	December 31, 2022		December 31, 2021	
	PSP	DSU	PSP	DSU
Balance beginning of year	526,519	162,512	504,004	118,490
Granted during the year	251,650	44,745	177,435	45,573
Paid out during the year	(185,910)	—	(170,089)	(6,321)
Expired during the year	(84,261)	—	(5,742)	—
Dividend reinvestment during the year	23,353	8,355	20,911	4,770
Balance end of year	531,351	215,612	526,519	162,512

A compensation expense of $3,171 was recorded during the year ended December 31, 2022 with respect to the PSP and DSU plans ($1,966 in 2021).

Dividends

a) 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, 2022, 73,865 shares (146,621 shares in 2021) were issued from treasury under the DRIP.

b) Dividend Declared

The following dividends were declared by the Corporation:

	Year ended December 31			
	2022		2021	
	($/share)	Total	($/share)	Total
Dividends declared on common shares	0.7200	146,957	0.7200	132,229
Dividends declared on Series A preferred shares	0.8110	2,757	0.8110	2,757
Dividends declared on Series C preferred shares	1.4375	2,875	1.4375	2,875

Dividend Declared not recognized at the end of the reporting period

The following dividends were paid by the Corporation on April 17, 2023:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series B Preferred Share [1]	Dividend per Series C Preferred Share
February 22, 2023	March 31, 2023	April 17, 2023	$ 0.180	$ 0.202750	$ 0.181875	$ 0.359375

1. As at December 31, 2022, there were no outstanding Series B Preferred Shares.

23. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Foreign currency translation differences for foreign operations	Changes in fair value of financial instruments designated as net investment hedges	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	Total
Balance as at January 1, 2022	(35,878)	574	(11,987)	(3,333)	(50,624)
Exchange differences on translation of foreign operations	97,131	—	—	—	97,131
Hedging (loss) gain	—	(3,484)	220,511	9,683	226,710
Share of non-controlling interest	(15,633)	(3,453)	(7,166)	—	(26,252)
Buyback of non-controlling interests	(2,609)	5,040	3,872	—	6,303
Related deferred tax expense	—	—	(53,990)	(2,608)	(56,598)
Balance as at December 31, 2022	43,011	(1,323)	151,240	3,742	196,670

	Foreign currency translation differences for foreign operations	Changes in fair value of financial instruments designated as net investment hedges	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	Total
Balance as at January 1, 2021	(33,612)	(4,832)	(66,010)	(7,242)	(111,696)
Exchange differences on translation of foreign operations	778	—	—	—	778
Hedging gain	—	7,773	78,652	5,303	91,728
Share of non-controlling interest	(3,044)	(2,367)	(2,746)	—	(8,157)
Related deferred tax recovery	—	—	(21,883)	(1,394)	(23,277)
Balance as at December 31, 2021	(35,878)	574	(11,987)	(3,333)	(50,624)

24. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a) Changes in non-cash operating working capital items

	Year ended December 31	
	2022	2021
Accounts receivable	(27,704)	(3,984)
Prepaids and other	(1,493)	(5,472)
Accounts payable and other payables	14,679	(11,999)
	(14,518)	(21,455)

b) Additional information

	Year ended December 31	
	2022	2021
Finance costs paid relative to operating activities before interest on leases	(221,662)	(185,324)
Interest on leases paid relative to operating activities	(6,699)	(4,533)
Capitalized interest relative to investing activities	(1,654)	(3,025)
Capitalized interest on leases relative to investing activities	(397)	(1,815)
Total finance costs paid	(230,412)	(194,697)
Non-cash transactions:		
Change in unpaid property, plant and equipment	36,444	(29,012)
Investment tax credits	8,535	14,070
Change in other long-term assets	261	—
Change in unpaid project development costs	546	1,874
Remeasurement of other liabilities	(41,276)	(23,748)
Initial measurement of other liabilities	11,453	8,447
New obligation under financing agreement	—	19,642
Common shares issued through the conversion of convertible debentures	—	2,306
Common shares issued through equity based compensation	2,114	3,174
Common shares issued through dividend reinvestment plan	1,301	3,312
Common shares issued upon acquisition	—	89,437

c) Changes in liabilities arising from financing activities

	Year ended December 31	
	2022	2021
Changes in long-term loans and borrowings		
Long-term debt at beginning of period	4,924,435	4,813,881
Increase in long-term debt	1,737,819	1,686,133
Repayment of long-term debt	(1,509,591)	(1,568,183)
Reclassification of interest payable	23,315	—
Payment of deferred financing costs	(20,278)	(3,381)
Business acquisitions (Note 4)	478,488	196,505
Investment tax credits	—	(117,904)
Tax attributes	(2,453)	(43,290)
Production tax credits	(64,729)	(47,985)
Convertible debentures converted into common shares	—	(2,306)
Other non-cash finance costs	62,715	55,022
Net foreign exchange differences	129,489	(44,057)
Long-term loans and borrowings at end of period	5,759,210	4,924,435

25. NON-WHOLLY-OWNED SUBSIDIARIES

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, 2022	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2021
Harrison Hydro L.P. and its subsidiaries	Canada	49.99 %	49.99 %	(18,770)	(6,044)	19,151	37,921
Kwoiek Creek Resources, L.P. (1,2)	Canada	50.00 %	50.00 %	(2,942)	(1,471)	(17,826)	(14,884)
Mesgi'g Ugju's'n (MU) Wind Farm L.P. (1,2)	Canada	50.00 %	50.00 %	11,303	11,402	(5,391)	(6,189)
Innergex Sainte-Marguerite, S.E.C.	Canada	49.99 %	49.99 %	(3,003)	(1,750)	(18,694)	(15,691)
Innergex Europe (2015) Limited Partnership, and its subsidiaries[3]	Canada/ Europe	— %	30.45 %	3,999	715	—	(2,244)
Mountain Air Alternatives LLC, and its subsidiaries[4]	United States	— %	37.75 %	2,044	2,446	—	57,537
Innergex HQI USA LLC, and its subsidiaries (2)	United States	50.00 %	50.00 %	(423)	1,319	186,595	203,189
Others	Various	Various	Various	(1,704)	(206)	6,397	7,929
				(9,496)	6,411	170,232	267,568

1. The Corporation owns more than 50% of the economic interest in the subsidiary.
2. Based on the terms of agreements under which these entities were established, the Corporation is exposed to, and has right to, variable returns from its involvement with the investee, and has the current ability to direct these entities's activities that most significantly affect the returns.
3. On October 4, 2022, the Corporation acquired the remaining ownership interests in Innergex Europe (2015) Limited Partnership. Refer to note 4 c)
4. On December 14, 2022, the Corporation acquired the remaining ownership interests in Mountain Air Alternatives LLC. Refer to note 4 c)

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, 2022						
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex Europe (277-day period)[1 2]	Mountain Air (348-day period)[3]	Innergex HQI USA
Summary Statements of Earnings (Loss) and Comprehensive Income (Loss)							
Revenues	38,130	14,870	58,966	9,484	58,311	35,392	54,525
Expenses	75,675	20,753	28,841	15,491	45,176	29,974	55,371
Net (loss) earnings	(37,545)	(5,883)	30,125	(6,007)	13,135	5,418	(846)
Other comprehensive income	—	—	2,602	—	24,491	10,577	24,885
Total comprehensive (loss) income	(37,545)	(5,883)	32,727	(6,007)	37,626	15,995	24,039
Net (loss) earnings attributable to:							
Owners of the parent	(18,775)	(2,941)	18,822	(3,004)	9,136	3,374	(423)
Non-controlling interests	(18,770)	(2,942)	11,303	(3,003)	3,999	2,044	(423)
	(37,545)	(5,883)	30,125	(6,007)	13,135	5,418	(846)
Total comprehensive (loss) income attributable to:							
Owners of the parent	(18,775)	(2,941)	20,447	(3,004)	26,169	9,958	12,020
Non-controlling interests	(18,770)	(2,942)	12,280	(3,003)	11,457	6,037	12,019
	(37,545)	(5,883)	32,727	(6,007)	37,626	15,995	24,039
Summary Statements of Cash Flows							
Cash flows from operating activities	1,177	6,294	44,634	2,817	91,860	19,573	43,212
Cash flows used in financing activities	(13,342)	(2,021)	(45,016)	(2,913)	(71,036)	(17,365)	(57,225)
Cash flows used in investing activities	(2,650)	(1,745)	(689)	731	58	(330)	—
Effects on exchange rate changes on cash and cash equivalents	—	—	—	—	(3,547)	742	445
Net change in cash and cash equivalents	(14,815)	2,528	(1,071)	635	17,335	2,620	(13,568)
Distributions paid to non-controlling interests	—	—	11,482	—	—	7,387	28,613

1. On October 4, 2022, the Corporation acquired the remaining ownership interests in Innergex Europe (2015) Limited Partnership.
2.The cash flows from operating activities include a realized gain of $43,458 related to the monetization of the Euro/CAD foreign exchange forward contracts. The cash flows from financing activities include the reimbursement of the debentures for a total consideration of $96,350, partially offset by a capital contribution from the parent company in the amount of $53,042.
3.On December 14, 2022, the Corporation acquired the remaining ownership interests in Mountain Air Alternatives LLC.

	Year ended December 31, 2021						
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex Europe	Mountain Air	Innergex HQI USA
Summary Statements of Earnings (Loss) and Comprehensive Income (Loss)							
Revenues	51,296	18,216	56,761	11,611	88,593	36,101	15,678
Expenses	63,386	21,158	25,363	15,111	86,245	29,609	13,040
Net (loss) earnings	(12,090)	(2,942)	31,398	(3,500)	2,348	6,492	2,638
Other comprehensive income (loss)	—	—	2,339	—	6,818	(258)	10,332
Total comprehensive (loss) income	(12,090)	(2,942)	33,737	(3,500)	9,166	6,234	12,970
Net (loss) earnings attributable to:							
Owners of the parent	(6,046)	(1,471)	19,996	(1,750)	1,633	4,046	1,319
Non-controlling interests	(6,044)	(1,471)	11,402	(1,750)	715	2,446	1,319
	(12,090)	(2,942)	31,398	(3,500)	2,348	6,492	2,638
Total comprehensive (loss) income attributable to:							
Owners of the parent	(6,046)	(1,471)	21,486	(1,750)	6,375	3,880	6,485
Non-controlling interests	(6,044)	(1,471)	12,251	(1,750)	2,791	2,354	6,485
	(12,090)	(2,942)	33,737	(3,500)	9,166	6,234	12,970
Summary Statements of Cash Flows							
Cash flows from operating activities	19,912	551	39,227	2,339	40,376	14,636	10,870
Cash flows used in financing activities	(12,295)	(1,996)	(40,337)	(2,637)	(35,642)	(14,002)	—
Cash flows used in investing activities	(1,885)	(2,115)	(356)	(2)	(2,961)	—	—
Effects on exchange rate changes on cash and cash equivalents	—	—	—	—	(4,125)	—	274
Net change in cash and cash equivalents	5,732	(3,560)	(1,466)	(300)	(2,352)	634	11,144
Distributions paid to non-controlling interests	—	—	9,769	—	—	4,617	—

Summary Statements of Financial Position

	As at December 31, 2022				
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex HQI USA
Current assets	14,035	6,014	21,937	2,319	11,877
Non-current assets	539,070	164,068	260,700	114,685	368,126
	553,105	170,082	282,637	117,004	380,003
Current liabilities	29,399	17,409	17,252	9,608	2,512
Non-current liabilities	448,380	196,552	233,333	128,223	4,292
Equity (deficit) attributable to owners	56,175	(26,053)	37,443	(2,133)	186,604
Non-controlling interests (deficit)	19,151	(17,826)	(5,391)	(18,694)	186,595
	553,105	170,082	282,637	117,004	380,003

	As at December 31, 2021						
	Harrison	Kwoiek	Mesgi'g Ugju's'n	Sainte-Marguerite	Innergex Europe	Mountain Air	Innergex HQI USA
Current assets	33,400	7,640	20,327	2,237	63,729	16,154	22,345
Non-current assets	550,515	164,945	272,273	118,392	802,868	300,334	388,646
	583,915	172,585	292,600	120,629	866,597	316,488	410,991
Current liabilities	29,661	12,139	16,188	8,759	142,878	7,151	587
Non-current liabilities	441,383	198,442	246,488	126,690	776,687	150,819	4,018
Equity (deficit) attributable to owners	74,950	(23,112)	36,113	871	(50,724)	100,981	203,197
Non-controlling interests (deficit)	37,921	(14,884)	(6,189)	(15,691)	(2,244)	57,537	203,189
	583,915	172,585	292,600	120,629	866,597	316,488	410,991

26. RELATED PARTY TRANSACTIONS

a) Key management personnel compensation

The following are transactions that the Corporation engaged with its key management personnel. The members of the Board of Directors as well as the President and CEO, CFO, CAO, Chief Legal Officer and Secretary, Chief Human Resources Officer and all the Senior Vice Presidents and Vice Presidents are key management personnel of the Corporation.

	Year ended December 31	
	2022	2021
Salaries and short-term benefits	7,670	7,188
Board of Directors' fees	1,016	1,072
Performance share plan	3,172	3,205
Share-based payments	35	87
	11,893	11,552

b) Transactions with partners

Related party transactions conducted in the normal course of operations are measured at an 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:

- Common shares issued to Hydro-Québec in 2022 and 2021 (see Note 22 - Shareholders' Capital)
- Sales made under PPAs with Hydro-Québec (see Note 31 - Major Customers)
- EVLO, a subsidiary of Hydro-Québec, provided battery at the Tonnerre Energy storage project
- Acquisition of the remaining interests in Innergex Europe (2015) Limited Partnership from its partner Régime de Rentes du Mouvement Desjardins (see Note 4 - Business acquisitions)
- Acquisition of the remaining interests in Mountain Air Alternatives LLC from its partner, an affiliate of MetLife Investment Management (see Note 4 - Business acquisitions)

27. 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. 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, 2022		As at December 31, 2021	
	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*	17,178	17,178	1,420	1,420
Non-current financial liabilities measured at amortized cost					
Long-term loans and borrowings	*Level 2*	5,759,210	5,934,241	4,924,435	5,027,286
Derivative financial instruments measured at fair value					
Interest rate swaps	*Level 2*	98,138	98,138	(78,482)	(78,482)
Foreign exchange forwards	*Level 2*	(3,555)	(3,555)	2,485	2,485
Power and basis hedges	*Level 3*	(69,333)	(69,333)	16,559	16,559

Other investments
The valuation model considers the present value of expected payments, discounted using a risk-adjusted discount rate.

Long-term loans and borrowings
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 payments 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 values of the power hedges are calculated using a discounted cash flow model. The fair value calculation of power hedges gives rise to measurement uncertainty as the power price curves are constructed using various methodologies and assumptions, which consider certain unobservable inputs. As at December 31, 2022, the forward power prices used in the calculation of fair value were as follows:

With respect to the Phoebe power hedge, ERCOT South Hub forward power prices are expected to be in a range of US$30.48 to US$100.10 per MWh between January 1, 2023 and June 30, 2031.

With respect to the Salvador power hedges, Polpaico node future power prices are expected to be in a range of US $0.19 to US$127.44 per MWh between January 1, 2023 and December 31, 2030.

Further information is provided below with regard 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) a combination of observable exchange prices and over-the-counter broker quotes obtained through November 2030; (2) for the seven remaining months until June 2031, extrapolated prices based on the growth rate implicit in traded NYMEX Natural Gas Futures prices.

Salvador power hedges: The fair value of the power hedges is derived from future power price forecasts that are not based on observable market data. Such forecasts are constructed using various assumptions depending on historical market prices, supply, demand and congestion volumes observed on the Chilean grid, as well as econometric models. In addition, as the notional volume of the power hedges is not contractually fixed, the estimated volume is determined using various assumptions such as the expected demand and volume of power to be successfully settled through the market bidding process.

The fair value estimates are subject to a credit risk adjustment that reflects the credit risk of the Corporation or of the counterparty.

The changes in the fair value of the derivative instrument are recognized in the consolidated statements of earnings (loss), as change in fair value of financial instruments.

Interest rate benchmark reform

The Corporation holds interest rate swaps for risk management purposes that are designated in cash flow hedging relationships. The interest rate swaps have floating legs that are indexed to either LIBOR, CDOR, or EURIBOR.

London Interbank Offered Rate ("LIBOR")

On March 5, 2021, the Financial Conduct Authority (UK), announced that all LIBOR settings for all currencies will either cease or no longer be representative after i) December 31, 2021, for Sterling, Euro, Swiss Franc and Japanese Yen LIBOR settings, and certain USD LIBOR tenors; and ii) June 30, 2023 for the USD LIBOR 1-month, 3-month, 6-month and 12-month tenors. The Corporation’s LIBOR swaps and cash flow hedging relationships extend beyond the anticipated cessation date for LIBOR.

The Corporation has evaluated the extent to which its cash flow hedging relationships are subject to uncertainty driven by the IBOR reform. The Corporation’s hedged items and hedging instruments continue to be indexed to LIBOR. The benchmark rates are quoted each day and the LIBOR cash flows are exchanged with counterparties as usual.

There is uncertainty about when and how replacement may occur with respect to the relevant hedged items and hedging instruments. Such uncertainty may impact the hedging relationship, which may experience ineffectiveness attributable to market participants’ expectations of when the shift from the existing IBOR benchmark rate to an alternative benchmark interest rate will occur. This transition may occur at different times for the hedged item and hedging instrument, which may lead to hedge ineffectiveness. The Corporation has measured its hedging instruments indexed to LIBOR using available quoted market rates for LIBOR-based instruments of the same tenor and similar maturity and has measured the cumulative change in the present value of hedged cash flows attributable to changes in LIBOR on a similar basis. The Corporation’s notional amount exposure to LIBOR designated in hedging relationships is US$207,200 ($280,632) as at December 31, 2022.

Canadian Dollar Offered Rate ("CDOR")

While CDOR is not anticipated to immediately be retired, the Bank of Canada expects its relevance to decline, like other credit-based benchmarks, as markets globally move to risk-free rates. While the 1-month, 2-month and 3-month tenors are not expected to be affected for the foreseeable future, the calculation and publication of the 6-month and 12-month CDOR tenors ceased from May 17, 2021 onwards, with no impact for the Corporation.

Euro Interbank Offered Rate ("EURIBOR")

In 2019, the EURIBOR has been authorized by the competent authority under the European Union Benchmarks Regulation. This allows market participants to continue to use EURIBOR for both existing and new contracts and the Corporation expects that EURIBOR will continue to exist as a benchmark rate for the foreseeable future.

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 flows 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 flows. 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, 2022	December 31, 2021
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	None	20,000	20,000
Innergex	CAD	CDOR	2.30%	2024	None	20,000	20,000
Innergex	CAD	CDOR	4.25%	2031	2022	26,585	28,855
Innergex	CAD	CDOR	1.89%	2029	2023	20,000	20,000
Innergex	CAD	CDOR	1.92%	2029	2023	20,000	20,000
Innergex	CAD	CDOR	2.08%	2034	2029	20,000	20,000
Innergex	CAD	CDOR	2.12%	2034	2023	20,000	20,000
Innergex	CAD	CDOR	2.24%	2049	2029	20,000	20,000
Innergex	CAD	CDOR	2.19%	2049	2029	25,000	25,000
Innergex	CAD	CDOR	3.97%	2025	None	50,000	—
Innergex	USD	SOFR	3.00%	2051	2023	81,854	—
Alterra	CAD	CDOR	2.57%	2031	None	100,000	—
Alterra	CAD	CDOR	2.60%	2031	None	12,500	—
Alterra	CAD	CDOR	2.51%	2028	None	42,500	—
Hydroelectric segment							
Ashlu Creek	CAD	CDOR	4.70%	2035	2025	37,654	39,588
Ashlu Creek	CAD	CDOR	4.70%	2035	2025	37,654	39,588
Fitzsimmons Creek	CAD	CDOR	2.85%	2041	2022	16,372	16,821
Duqueco	USD	LIBOR	1.05%	2033	None	—	114,966
Coyanco	USD	LIBOR	1.01%	2031	None	7,487	7,621
Wind segment							
Rougemont 1	EUR	EURIBOR	1.30%	2032	None	49,787	53,645
Rougemont 2	EUR	EURIBOR	1.30%	2032	None	30,455	32,781
Rougemont 2	EUR	EURIBOR	1.48%	2032	None	27,647	29,758
Vaites	EUR	EURIBOR	1.28%	2032	None	52,746	57,046
Cartier	CAD	CDOR	2.83%	2032	None	402,430	445,905
Mesgi'g Ugju's'n	CAD	CDOR	1.91%	2026	None	50,470	63,654
Cholletz	EUR	EURIBOR	2.64%	2030	None	9,296	10,387
Foard City	USD	LIBOR	2.07%	2029	2026	10,466	11,442
Foard City	USD	LIBOR	2.43%	2029	2026	7,699	9,299
Mountain Air	USD	LIBOR	2.03%	2029	None	19,051	19,311
Solar Segment							
Stardale	CAD	CDOR	3.60%	2032	None	64,021	66,613
Phoebe	USD	LIBOR	3.07%	2037	2026	130,753	125,968
Kokomo	USD	LIBOR	1.85%	2026	None	4,854	4,861
Spartan	USD	LIBOR	2.31%	2024	None	10,957	10,846
Hillcrest	USD	LIBOR	0.95%	2041	2028	89,363	89,214
HP Solar I	USD	SOFR	2.40%	2048	2041	55,519	—
Pampa Elvira	USD	LIBOR	1.90%	2022	None	—	2,252
						1,695,720	1,548,021

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 1.3544 and EURO swaps are converted at a fixed rate of CAD 1.4458.

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, 2022				
Interest rate swaps	27	(27)	8,470	(8,554)
December 31, 2021				
Interest rate swaps	150	(23)	8,568	(8,758)

(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 Euros. 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]:

		Notional Amounts	
Contracts	Maturity	December 31, 2022	December 31, 2021
Contracts used to hedge the foreign exchange risk			
Foreign exchange forwards amortizing until 2043, allowing conversion at a fixed rate of CAD 1.4838/Euro	2024	115,317	—
Foreign exchange forwards amortizing until 2041, allowing conversion at a fixed rate of CAD 1.7220/Euro	2022	—	147,097
Foreign exchange forwards amortizing until 2042, allowing conversion at a fixed rate of CAD 1.7196/Euro	2022	—	42,817
Foreign exchange forwards amortizing until 2041, allowing conversion at a fixed rate of CAD 1.6650/Euro	2023	—	97,509
Foreign exchange forwards amortizing until 2043, allowing conversion at a fixed rate of CAD 1.7516/Euro	2023	—	143,753
Foreign exchange forwards amortizing until 2043, allowing conversion at a fixed rate of CAD 1.7698/Euro	2023	—	69,436
		115,317	500,612

1. The Corporation 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, 2022				
Foreign exchange forwards	(140)	140	(642)	643
December 31, 2021				
Foreign exchange forwards	(3,127)	3,126	(854)	855

(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

The Corporation is subject, under the Phoebe solar project, to a 12-year power hedge maturing on June 30, 2031. The power hedge was designated for hedge accounting purposes until September 30, 2019. 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. The Phoebe power hedge is accounted for at fair value, with changes recognized as changes in fair value of financial instruments. The unrealized net loss recognized as change in fair value of financial instruments amounts to a $74,805 for the year ended December 31, 2022.

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)	
	10 % increase	10% decrease
December 31, 2022		
Power hedge	(29,895)	29,895
December 31, 2021		
Power hedge	(25,672)	26,329

Salvador power hedges

The Corporation is subject, under the Salvador solar project, to a portfolio of synthetic power purchase agreements ("PPA"), which act as power hedges. Salvador power hedges are accounted for at fair value, with subsequent changes being recognized as change in fair value of derivative financial instruments. The unrealized net gain recognized as change in fair value of financial instruments amounts to $7,267 for the year ended December 31, 2022.

Sensitivities

A reasonably possible change of 10% in the Polpaico node projected 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)	
	10 % increase	10% decrease
December 31, 2022		
Power hedge	(2,318)	2,318
December 31, 2021		
Power hedge	(1,312)	1,312

(iv) Hedge accounting

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, 2022 the following items were designated as hedging instruments to mitigate the interest rate 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	1,653,908	107,040	(4,023)
Net investment hedges:			
Foreign exchange risk			
Foreign exchange forwards	92,246	95	(3,013)

The following table summarizes the impact of hedge ineffectiveness and hedging gains (losses) as at December 31, 2022:

	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	224,168	2,756	1,165
Power price risk			
Power hedge [1]	—	—	3,351
Hedge of net investment in a foreign operation:			
Foreign exchange risk			
Foreign exchange forwards	3,484	206	452

1. The balance of cash flow hedge reserve relating to power price risk for which hedge accounting is no longer applied is $26,081.

Ineffectiveness is accounted for in the change in fair value of 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, 2022, the Corporation was holding cash and cash equivalents, restricted cash (Note 12) and reserves included in other long-term assets (Note 18). 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.

Most of the Corporation's trade receivables in Chile relate to electricity sold to distribution companies, with the majority being sold to large distribution companies 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, 2022, $15,199 ($5,434 in 2021) of trade and other receivables were more than 90 days overdue and a total write-off of impaired receivables of $2,341 (nil in 2021) 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

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 $123,665 as at December 31, 2022 (negative working capital of $344,850 in 2021). The Corporation considers its current level of working capital and revolving term credit facility availability to be sufficient to meet its needs, also considering the $150,000 subordinated unsecured term loan, effectively refinanced on February 1, 2023, classified as current as at December 31, 2022 (see Note 20). The Corporation limits its excess cash position through repayments of its revolving term credit facility. When required, the Corporation can use its revolving term credit facility of which $174,877 was available as at December 31, 2022 ($252,954 in 2021). 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 18) and is covered by insurance plans.

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-derivative financial liabilities				
Accounts payable and other payables	248,659	—	—	248,659
Long-term loans and borrowings[1]	593,353	1,948,790	4,188,134	6,730,277
Other liabilities	254	9,603	36,249	46,106
Lease liabilities	4,878	15,135	53,729	73,742
Derivative financial liabilities				
Interests rate swaps	3,050	13,698	7,230	23,978
Foreign exchange forwards	—	6,874	—	6,874
Power Hedge	17,891	24,830	13,548	56,269
Total	868,085	2,018,930	4,298,890	7,185,905

1. The contractual cash flows include debt principal and interest payments.

28. COMMITMENTS

a. Power Purchase Agreements

Quebec facilities
Under PPAs with terms varying from 20 to 25 years and expiring between 2024 and 2046, 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.

The PPA for Portneuf reached the end of there inital 25-year term in May 2021. The Corporation sent to Hydro-Québec its notice of automatic renewal for an additional 25-year term. Discussions on the renewal terms and conditions are underway, in accordance with the renewal process of the initial PPA.

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 Sekw'el'was Cayoose Creek Band announced that they reached an agreement with BC Hydro for the renewal of the Walden North Facility's electricity purchase agreement (the "Walden EPA Renewal"). Cayoose Creek Power Limited Partnership and BC Hydro agreed to terminate the Walden EPA Renewal pursuant to its terms and to continue to transact pursuant to the terms of the original electricity purchase agreement initially entered into between BC Hydro and ESI Power Corp., dated August 16, 1990 and the forbearance agreement initially entered into between BC Hydro and ESI Power-Walden Corporation, dated April 1, 2014. The Corporation expects EPA negotiations to resume with BC Hydro shortly as BC Hydro filed its new Integrated Resource Plan with the BCUC.

On April 16, 2018, the Corporation announced that it reached an agreement with BC Hydro for the renewal of the EPA of the Brown Lake Facility for a 40-year term (the "Brown Lake EPA Renewal"). The Corporation and BC Hydro amended the Brown Lake EPA Renewal as suggested by the BCUC so that the Brown Lake EPA Renewal would have a term no longer than three years and ended on October 31, 2022. The Corporation signed a three-month extension, expiring on February 1, 2023. A decision was made to not renew the Brown Lake PPA with BC Hydro at this time. Discussions regarding various offtake oppotunities are currently in progress.

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 10 of the 16 wind facilities located in France.

Under PPA's with terms of three years, expiring in 2025, an offtaker agreed to purchase the electrical energy produced by the facilities of Antoigné, Porcien and Vallottes, located in France.

Under PPA's with terms of 10 years expiring in 2032, an offtaker agreed to purchase the electrical energy produced by Beaumont and Bois d'Anchat wind facilities located in France.

The Tonnerre energy storage project has been awarded a 7-year contract for differences offering a fixed-price contract for capacity certificate.

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 the Kokomo and Spartan solar facilities.

Under a PPA with a 15-year term and expiring in 2034, a client agreed to purchase all of the electricity produced by the Hillcrest solar facility.

Under a PPA with a 20-year term and expiring in 2033, Idaho Power Company agreed to purchase all of the electricity produced by the Mountain Air wind farm facilities.

Under a PPA with a 6-year term and expiring in 2027, Niagara Mohawk Power Corporation agreed to purchase all of the electricity produced by the Curtis Mills and Palmer Falls hydro facilities located in the state of New York.

Chile facilities

Under a PPA with a 10-year term and expiring in March 2023, the client agreed to purchase all of the energy produced by the Pampa Elvira solar facility located in Chile. Management is currently negotiating the extension of the contract until December 31, 2032; this process is currently with an agreed binding offer in process of drafting and signing contracts.

Under a PPA with terms varying from 4 to 8 years and expiring between 2023 and 2026, clients agreed to purchase all of the electricity produced by the Peuchen and Mampil Hydro facilities located in the Bio-Bio region.

Under a PPA with terms varying from 2 to 4 years and expiring between 2025 and 2026, clients agreed to purchase all of the electricity produced by the Guayacan Hydro facility.

Under PPAs with 20-year terms expiring between 2036 and 2041, clients agreed to purchase a portion of the electricity produced by the Sarco, Cuel and Aurora Wind facilities.

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 financial 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.

Hale Kuawehi Solar LLC has entered into a engineering, procurement, and supply agreement to construct the solar project in Hawaii, U.S.

c. Summary of commitments

As at December 31, 2022, the expected schedule of commitment payments is as follows:

Year of expected payment	Under 1 year	1 to 5 years	Thereafter	Total
Purchase obligations	36,437	175,830	369,293	581,560
Variable payments on lease contracts	2,095	8,720	5,436	16,251
Total	38,532	184,550	374,729	597,811

29. 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.

BC Hydro curtailment notices

In May 2020, Innergex received notices from BC Hydro in relation to six of the Corporation's hydroelectric facilities in British Columbia stating that BC Hydro would not accept and purchase energy under the applicable electricity purchase agreements ("EPAs") above a specified curtailment level for the period from May 22, 2020 to July 20, 2020. The specified curtailment levels were 0.0 MW/h for the Jimmie Creek (accounted for using the equity method), Upper Lillooet River, Northwest Stave River, and Boulder Creek facilities, 2.0 MW/h for the Tretheway Creek facility and 4.0 MW/h for the Big Silver Creek facility.

BC Hydro cited the current COVID-19 pandemic and related governmental measures taken in response to it as constituting a "force majeure" event under the EPAs, and resulting in a situation in which BC Hydro was allegedly unable to accept or purchase energy under the EPAs. The notices to Innergex followed public statements by BC Hydro regarding measures it was taking to address the reduced electricity demand during the COVID-19 pandemic and related challenges to the safe operation of its hydroelectric system.

Innergex disputed that the pandemic and related governmental measures in any way prevented BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enabled it to invoke "force majeure" provisions under the EPAs to suspend these obligations. Innergex acknowledges that BC Hydro retains "turn-down" rights under the EPAs, which enable it to require Innergex to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk. Where BC Hydro exercises this right, it is required under the EPAs to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. Innergex has complied with BC Hydro's curtailment request, but has done so under protest, seeking to enforce its rights under the EPAs on the basis described above. For the period from May 22, 2020 to July 20, 2020, actual eligible energy revenue that would have been produced at the facilities in the absence of the curtailment amounted to $12,456 ($14,183 on a Revenues Proportionate[1] basis), respectively. The dispute was settled in the first quarter of 2022 to Innergex's satisfaction.

Harrison Hydro L.P. Water Rights

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 $3,181 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. The Limited Partnerships have filed their response to petition on April 14, 2020. The hearing took place in Victoria in the last week of September 2020. A decision was rendered on February 9, 2021 by the Supreme Court of British Columbia, which concluded that the Environmental Appeal Board's decision was reasonable, and dismissed the Comptroller of Water Rights' petition accordingly. The Comptroller of Water Rights subsequently appealed the decision of the Supreme Court of British Columbia, which was unanimously dismissed by the British Columbia Court of Appeal on January 7, 2022. The Corporation recognized the amount of $3,181 in the consolidated statements of earnings (loss) during the year ended December 31, 2019. A total amount of $3,385, including interests, was received by the Corporation during the first quarter of 2022.

[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 Note 31, Segment Information, for more information.

Innavik EPC Agreement

On January 25, 2023 a legal hypothec has been registered by the contractor against the Innavik hydroelectric project ("Innavik" or "the project"), a joint venture company, in the amount of $57,768, representing the contractor’s claim for payment of additional costs under the EPC Agreement with Innavik. The Corporation disputes that claim in good faith and, unless the contractor discharges the legal hypothec at its request, will take legal action to cause the legal hypothec to be removed from title. As at December 31, 2022, while continuing to dispute the claim, the project recognized a provision for construction cost overruns, estimated based on a range of possible outcomes that are materially lower than the amounts claimed by the contractor.

30. CAPITAL MANAGEMENT

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 $7,245,637 as at December 31, 2022.

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 or, for qualifying projects in the United States, through tax equity 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, 2022, the Corporation and its subsidiaries have met all material financial and non-financial conditions, related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements, 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.

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.

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.

"Revenues Proportionate" are Revenues plus Innergex's share of Revenues of the operating joint ventures and associates, other income related to PTCs, and Innergex's share of the operating joint ventures and associates' other income related to PTCs. “Adjusted EBITDA” represents net earnings (loss), to which are added (deducted) income tax expense (recovery), finance costs, depreciation and amortization, impairment charges, other net income, share of (earnings) loss of joint ventures and associates, and change in fair value of financial instruments. "Adjusted EBITDA Proportionate" represents Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the operating joint ventures and associates, other income related to PTCs, and Innergex's share of the operating joint ventures and associates' other income related to PTCs. Revenues Proportionate, Adjusted EBITDA and Adjusted EBITDA Proportionate 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 Revenues Proportionate, Adjusted EBITDA and Adjusted EBITDA Proportionate should not be construed as an alternative to net earnings (loss), as determined in accordance with IFRS.

Except for Revenues Proportionate, Adjusted EBITDA and Adjusted EBITDA Proportionate 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, 2022 Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	336,645	420,529	113,320	870,494
Innergex's share of revenues of joint ventures and associates	44,328	16,207	—	60,535
PTCs and Innergex's share of PTCs generated	—	64,729	—	64,729
Segment Revenues Proportionate	380,973	501,465	113,320	995,758
Segment Adjusted EBITDA	250,510	317,487	89,021	657,018
Innergex's share of Adjusted EBITDA of joint ventures and associates	34,554	12,164	—	46,718
PTCs and Innergex's share of PTCs generated	—	64,729	—	64,729
Segment Adjusted EBITDA Proportionate	285,064	394,380	89,021	768,465

Year ended December 31, 2022	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	110,181	24,840	—	135,021
Property, plant and equipment acquired through business acquisitions	—	572,284	22,188	594,472
Acquisition of property, plant and equipment	5,502	5,313	1,814	12,629

1. Segment totals include only operating projects.

Year ended December 31, 2021 Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	277,302	349,786	120,120	747,208
Innergex's share of revenues of joint ventures and associates	50,547	60,489	885	111,921
PTCs and Innergex's share of PTCs generated	—	54,018	—	54,018
Segment Revenues Proportionate	327,849	464,293	121,005	913,147
Segment Adjusted EBITDA	212,436	276,859	103,702	592,997
Innergex's share of Adjusted EBITDA of joint ventures and associates	38,547	54,989	554	94,090
PTCs and Innergex's share of PTCs generated	—	54,018	—	54,018
Segment Adjusted EBITDA Proportionate	250,983	385,866	104,256	741,105

Year ended December 31, 2021	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	108,911	24,130	—	133,041
Property, plant and equipment acquired through business acquisitions	499,024	—	10,069	509,093
Transfer of assets upon commissioning	—	358,581	291,636	650,217
Acquisition of property, plant and equipment during the year	5,826	13,677	945	20,448

1. Segment totals include only operating projects.

The following table presents a reconciliation of the non-IFRS measures to their closest IFRS measures:

	Year ended December 31, 2022				Year ended December 31, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	870,494	60,535	64,729	995,758	747,208	111,921	54,018	913,147
Net loss	(91,115)	—	—	(91,115)	(185,394)	—	—	(185,394)
Income tax expense (recovery)	(6,577)	—	—	(6,577)	(26,240)	(31)	—	(26,271)
Finance costs	317,842	17,757	—	335,599	252,255	23,382	—	275,637
Depreciation and amortization	336,053	16,801	—	352,854	255,640	23,051	—	278,691
Impairment of long-term assets	47,868	—	—	47,868	36,986	112,609	—	149,595
EBITDA	604,071	34,558	—	638,629	333,247	159,011	—	492,258
Other net income, before PTCs	(4,190)	(342)	—	(4,532)	(41,637)	1,947	—	(39,690)
Production tax credits ("PTCs")	(64,729)	—	64,729	—	(47,984)	(6,034)	54,018	—
Share of (earnings) losses of joint ventures and associates:	(14,382)	14,382	—	—	189,889	(189,889)	—	—
Change in fair value of financial instruments	64,145	(1,880)	—	62,265	92,122	129,055	—	221,177
Adjusted EBITDA	584,915	46,718	64,729	696,362	525,637	94,090	54,018	673,745
Unallocated expenses:								
General and administrative	47,363	—	—	47,363	39,993	—	—	39,993
Prospective projects	24,740	—	—	24,740	27,367	—	—	27,367
Segment Adjusted EBITDA	657,018	46,718	64,729	768,465	592,997	94,090	54,018	741,105

Geographic segments

As at December 31, 2022, excluding its investments in joint ventures and associates which are accounted for as equity method, the Corporation had interests in the following operating assets: 33 hydroelectric facilities, 8 wind farms and 1 solar farm in Canada, 16 wind farms and 1 storage facility in France, and 3 hydroelectric facility, 8 wind farms and 4 solar farms in the United States, and 4 hydroelectric facilities, 3 wind farms and 3 solar farms in Chile. The Corporation operates in four principal geographical areas, which are detailed below:

	Year ended December 31	
	2022	2021
Revenues		
Canada	427,910	433,192
United States	229,446	187,332
Chile	121,021	38,091
France	92,117	88,593
	870,494	747,208

As at	December 31, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,246,979	3,390,029
United States	2,364,160	2,301,353
Chile	1,549,679	423,856
France	753,161	801,752
	7,913,979	6,916,990

1. Includes the investments in joint ventures and associates

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	
		2022	2021
Hydro-Québec	Hydroelectric and wind	235,234	219,942
British Columbia Hydro and Power authority	Hydroelectric generation	158,325	187,973
Électricité de France	Wind	89,675	88,593
		483,234	496,508

32. SUBSEQUENT EVENTS

Acquisition of Sault Ste. Marie Solar Portfolio

On January 23, 2023, Innergex has entered into an agreement to acquire the 60 MW Sault Ste. Marie solar portfolio located in northwestern Ontario from Fengate Asset Management for a purchase price of $50,200, along with the assumption of $169,500 of existing debt. The acquisition is expected to close in Q1 2023 and is subject to certain regulatory approvals in Canada, key third party consents and other customary closing conditions.

Refinancing of the subordinated unsecured term loan

On February 1, 2023, Innergex has completed the refinancing of the subordinated unsecured term loan with a non-revolving term credit facility of $75,000 bearing interest at a fixed rate of 6.25% and maturing on February 1, 2025, and a non-revolving term credit facility of $75,000 bearing interest at a variable rate of 4.87%, based on the bankers' acceptance rates plus a spread of 1.85% which depends on leverage ratio, maturing on February 1, 2025. Concurrently, the Corporation concluded an interest rate swap to hedge a $50,000 portion of the credit facility notional that is subject to variable interest rates.

SHAREHOLDER INFORMATION

Head Office

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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:	***Computershare Investor Services Inc.*** 1500 Robert-Bourassa Blvd, Suite 700 Montreal QC H3A 3S8 Tel. 1 800 564.6253 514 982.7555 service@computershare.com

Common Shares - TSX: INE

Innergex Renewable Energy Inc. had 204,132,833 common shares outstanding as at December 31, 2022, with a closing price of $16.20 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 $0.8110 per share, payable quarterly on the 15th day of January, April, July and October. Series A preferred shares are redeemable by the Corporation since 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 $148.0 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 are redeemable since June 30, 2021.

Convertible Debentures - TSX: INE.DB.C

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for an aggregate principal amount of $142.1 million, bearing interest at a rate of 4.65% per annum, payable semi-annually on October 31 and April 30 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, 2026 and are redeemable since October 31, 2022.

Credit Rating by Fitch Rating

Innergex Renewable Energy Inc.	BBB-
Series A Preferred Shares	BB
Series C Preferred Shares	BB

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

Independent Auditor

KPMG LLP

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Pour la version papier, écrivez-nous à info@innergex.com

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