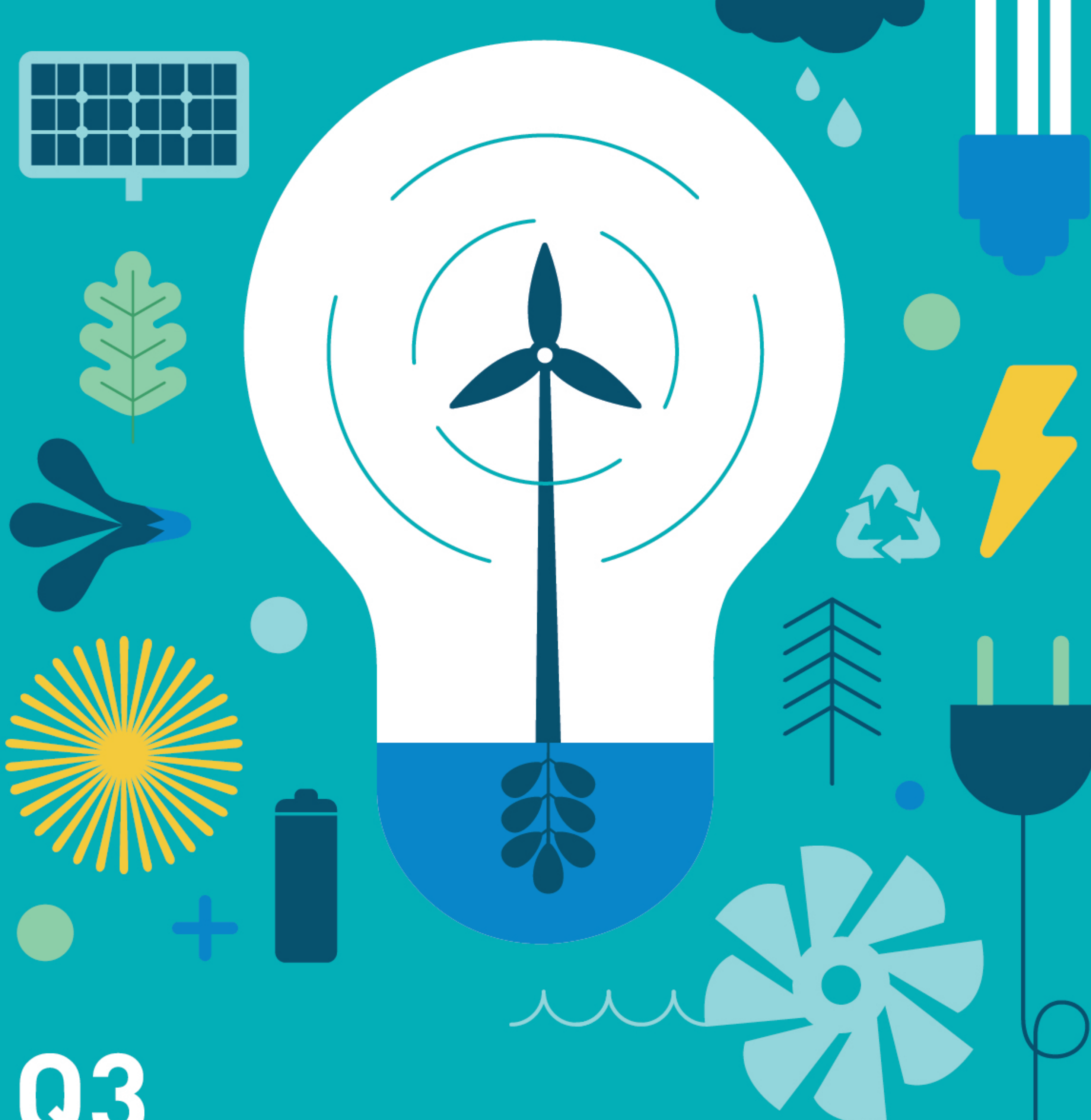
INNERGEX

Renewable Energy.
Sustainable Development.



Q3

Quarterly Report

For the Period Ended September 30, 2022

These condensed interim consolidated financial statements have not been audited by the Corporation's independent auditors.

For more than 30 years now, 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.

KEY FIGURES

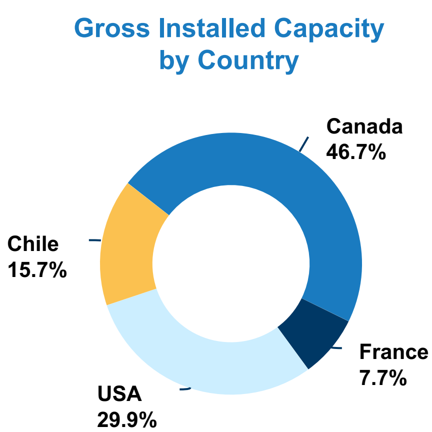
Innergex measures its performance using key performance indicators ("KPIs"). Innergex believes that these indicators are important, as they provide management and the reader with additional information about its production and cash-generating capabilities, its ability to pay dividends and fund its growth.

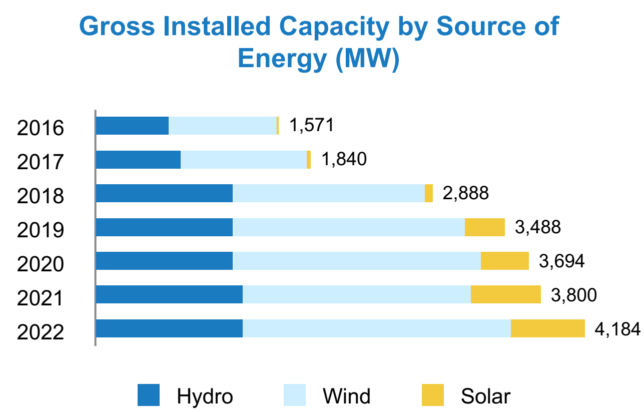
These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

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

Operational Key Performance Indicators

As at November 7, 2022, the Corporation has four geographic segments and three operating segments.





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.

INFORMATION ON COVID-19

The Corporation continues to closely monitor the impacts of COVID-19 and is actively managing its response by placing a priority on the health and safety of our employees, suppliers, business partners and the broader community. Innergex is adhering to pandemic response plans and is following guidance from government health departments with respect to conducting operations safely. To the extent possible, and as permitted by local guidelines, the Corporation is facilitating vaccination of its employees against COVID-19.

Power production activities have continued in all segments, as they have been deemed essential services in every region where the Corporation operates. Innergex's renewable power production is sold mainly through power purchase agreements, which include sufficient protection to prevent material reduction in demand, to financially solid counterparties, and no credit issues are anticipated.

Although our business is considered essential services, different government decisions in each region may have an impact on the ability of Innergex's employees, customers, suppliers and other business partners to conduct business activities as usual, and this could last for an extended period. This could have a material effect on our operating results, financial condition, liquidity, capital expenditures and the trading value of our securities, in particular:

- Impact of supply chain disruption on construction and development activities;
- Impact on employees and cybersecurity;
- Impact on liquidity;
- Impact on capital expenditures and costs;
- Impact on general electricity demand and on merchant prices.

The effects of COVID-19 on business may continue for an extended period, and the ultimate impact on the Corporation of the pandemic will depend on future developments that are uncertain and cannot be predicted including, and without limitations, the duration and severity of the pandemic, the duration of government mitigation measures, the effectiveness of the actions taken to contain and treat the disease, and the length of time it takes for normal economic and operating conditions to resume.

Since March 2020, Innergex has implemented numerous measures to protect employees, suppliers and business partners from COVID-19. In addition to standard operating procedures designed to maintain safe operations, the Corporation has implemented Communicable Disease Prevention Plans in each of its locations to provide guidance on health and safety measures to adopt regarding the COVID-19 pandemic. The Corporation is engaged in ongoing communications with employees, apprising them of its response to the pandemic. Innergex believes that its employees and suppliers can access its facilities safely and in compliance with relevant directives.

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 November 7, 2022, 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 9.6 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 13.5 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 November 7, 2022.

	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	662	330	—	—
Chile	3	—	332	—	332	—	—	—
Subtotal	35	3	2,278	368	2,032	362	—	—
SOLAR								
Canada	1	—	27	—	27	—	—	—
United States	4	5	467	280	466	280	—	320 [5]
Chile	3	—	153	—	138	—	150 [4]	—
Subtotal	8	5	647	280	631	280	150	320
STORAGE								
France	1	—	—	—	—	—	9	—
Chile	—	2	—	—	—	—	—	425 [6]
Subtotal	1	2	—	—	—	—	9	425
Total	84	13	4,184	768	3,582	731	159	745

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)), Paeahu (15 MW/60 MWh (4 hours)), Kahana (20 MW/80 MWh (4 hours)) and Barbers Point (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.

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

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 nine-month periods ended September 30, 2022, and reflects all material events up to November 7, 2022, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the unaudited condensed interim consolidated financial statements and the accompanying notes for the three- and nine-month periods ended September 30, 2022.

The unaudited condensed interim consolidated financial statements attached to this MD&A and the accompanying notes for the three- and nine-month periods ended September 30, 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 | Third Quarter 2022 – Growth Initiatives

On July 22, 2022, the Corporation announced the full commissioning of the 9 MW/9 MWh Tonnerre battery energy storage system in France. Tonnerre has been awarded a 7-year contract for difference 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 is effective since 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 in the United States Treasury (“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.

The **Prospective Projects** pipeline will allow several opportunities in the years to come, with 12 projects currently at an advanced stage, for a total 908 MW of installed capacity.

1- HIGHLIGHTS | Third Quarter 2022 – Selected Information

	Three months ended September 30		Nine months ended September 30			
	2022	2021	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized
OPERATING RESULTS						
Production (MWh)	2,736,471	2,290,086	7,896,968	6,472,058	—	6,472,058
Revenues	258,389	184,564	666,858	544,820	(54,967)	489,853
Operating, general, administrative and prospective projects expenses	77,231	62,042	202,302	156,494	—	156,494
Adjusted EBITDA[1]	181,158	122,522	464,556	388,326	(54,967)	333,359
Adjusted EBITDA Margin[1]	70.1 %	66.4 %	69.7 %	71.3 %	(3.2)%	68.1 %
Net Earnings (Loss)	20,980	(23,464)	(38,540)	(191,137)	64,219	(126,918)
Adjusted Net (Loss) Earnings[1]	(1,007)	11,905	(5,576)	3,023	—	3,023
PROPORTIONATE						
Production Proportionate (MWh)[1]	2,993,839	2,538,645	8,343,421	7,177,192	—	7,177,192
Revenues Proportionate[1]	296,612	221,960	764,182	682,096	(95,273)	586,823
Adjusted EBITDA Proportionate[1]	215,413	155,938	551,404	510,791	(95,273)	415,518
Adjusted EBITDA Proportionate Margin[1]	72.6 %	70.3 %	72.2 %	74.9 %	(4.1)%	70.8 %
COMMON SHARES						
Dividends declared on Common Shares	36,741	34,703	110,213	97,580	—	97,580
Dividends declared on Series A Preferred Shares	689	689	2,068	2,068	—	2,068
Dividends declared on Series C Preferred Shares	719	719	2,156	2,156	—	2,156
Weighted Average Number of Common Shares (in 000s)	203,523	182,692	201,265	177,044	—	177,044

	Trailing twelve months ended September 30			
	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized
CASH FLOW AND PAYOUT RATIO				
Cash Flow From Operating Activities[2]	412,447	267,354	17,093	284,447
Free Cash Flow[1,2]	158,996	91,211	15,789	107,000
Payout Ratio[1,2]	91 %	141 %	(20)%	121 %
Adjusted Payout Ratio[1,2]	78 %	96 %	— %	96 %

FINANCIAL POSITION As at	September 30, 2022	December 31, 2021
Total Assets	8,604,831	7,396,068
Total Liabilities	6,950,637	6,035,388
Equity Attributable to Owners	1,399,235	1,093,112
Non-Controlling Interests	254,959	267,568

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 nine-month period ended September 30, 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 | Third Quarter 2022 – Operating Performance

For the three-month period ended September 30, 2022, **Revenues** were up 40% to $258.4 million compared with the same period last year. The **hydroelectric** power generation segment recorded an increase in revenues mainly attributable to the acquisition of Curtis Palmer completed on October 25, 2021, and of the remaining 50% interest in Energía Llaima on July 9, 2021, for which results are now included in Innergex's consolidated revenues and by higher production at the facilities in British Columbia due to the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line in 2021. The increase in revenues in the **wind** power generation segment was mainly attributable to the commissioning of the Griffin Trail facility on July 26, 2021, the acquisition of Aela Generación S.A. and Aela Energía SpA (together "Aela") on June 9, 2022, and the increase in revenues from the new PPAs negotiated at some facilities in France. The increase was partly offset by lower revenues from lower wind regimes at some facilities in France combined with unfavourable exchange rates. The increase in revenues from the **solar** power generation segment was mostly due to the higher selling prices at the Phoebe facility and to the San Andrés Acquisition completed on January 28, 2022. This increase was partly offset by lower selling prices at the Salvador facility. Revenues Proportionate[1] were up 34% at $296.6 million compared with the same period last year.

For the three-month period ended September 30, 2022, **Operating, general, administrative and prospective projects expenses** were up 24% to $77.2 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 and to the acquisition of Curtis Palmer and the Chilean facilities in 2021. In the **wind** power generation segment, these expenses increased due to the Aela acquisition on June 9, 2022, partly offset by reduced operating costs at some facilities in the United States. The increase in the **solar** power generation segment is explained by higher operating expenses stemming from the commissioning of the Hillcrest facility in 2021 and the acquisition of San Andrés in Chile in 2022.

As a result of the factors explained above, the Adjusted EBITDA[1] was 48% higher at $181.2 million for three-month period ended September 30, 2022, compared with the same period last year. The Adjusted EBITDA Proportionate[1] reached $215.4 million, a 38% increase compared with the same period last year.

Innergex recorded net earnings of $21.0 million ($0.11 net earnings per share - basic and diluted) for the three-month period ended September 30, 2022, compared with a net loss of $23.5 million ($0.10 net loss per share - basic and diluted) for the corresponding period in 2021. This was mainly due to a net favourable $15.2 million change in the fair value of financial instruments, mainly related to the favourable change in foreign exchange forward curves in 2022 compared with the same period last year, and a $30.7 million decrease in impairment of long-term assets following the impairment charges recognized in 2021. These items were partly offset by a net unfavorable impact on net earnings related to tax attributes being allocated to tax equity investors, largely attributable to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility (a $12.9 million decrease in income tax expense and a $27.3 million decrease in other net income), a $23.9 million increase in finance costs, mainly attributable to the acquisitions, and the Griffin Trail and Hillcrest commissionings in 2021, and a $23.1 million increase in depreciation and amortization.

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[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 | Third Quarter 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 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 towards the Aela Acquisition and the construction and development activities. 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 September 30, 2022, is mainly due to the contribution from the acquisitions, the Hillcrest and Griffin Trail commissionings and the realized gain on financial instruments following the settlement of the interest rate swap as part of Innergex's refinancing of the non-recourse debt of its Chilean facilities. For the trailing twelve months ended September 30, 2022, Free Cash Flow[1] was impacted by the above.

1- HIGHLIGHTS | Subsequent Events

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, of which Innergex previously owned the majority interests, and has reimbursed the outstanding debentures for a total consideration of $96.4 million.

On October 5, 2022, as part of the financing of the acquisition of the remaining interests in its wind portfolio in France, Innergex monetized its Euro/CAD foreign exchange forward contracts for a total gain of $43.5 million and concurrently 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 are to take 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.

[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.

2- OVERVIEW OF OPERATIONS | Business Environment

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	25 %	11,843	100 %

1. The consolidated long-term average production is the annualized LTA for the facilities in operation as of November 7, 2022. 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.

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 shortage 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.

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

2- OVERVIEW OF OPERATIONS | Operating Facilities

Energy segment	Location	Three months ended September 30, 2022 Production (MWh)	Three months ended September 30, 2022 Production as a % of LTA	Three months ended September 30, 2021 Production (MWh)	Three months ended September 30, 2021 Production as a % of LTA	Three months Production % change	Nine months ended September 30, 2022 Production (MWh)	Nine months ended September 30, 2022 Production as a % of LTA	Nine months ended September 30, 2021 Production (MWh)	Nine months ended September 30, 2021 Production as a % of LTA	Nine months Production % change
HYDRO	Quebec	193,464	107 %	163,024	90 %	19 %	534,645	103 %	517,811	100 %	3 %
	Ontario	6,342	77 %	16,300	198 %	(61)%	51,640	97 %	49,462	93 %	4 %
	British Columbia	743,960	93 %	630,122	79 %	18 %	1,599,160	88 %	1,600,299	88 %	— %
	United States[3]	58,229	78 %	13,242	79 %	340 %	263,600	92 %	35,347	85 %	646 %
	Chile[4]	146,618	92 %	110,611	74 %	— %	302,557	91 %	110,611	74 %	— %
	Subtotal	**1,148,613**	**94 %**	**933,299**	**81 %**	**23 %**	**2,751,602**	**91 %**	**2,313,530**	**89 %**	**19 %**
WIND	Quebec	440,981	98 %	437,765	98 %	1 %	1,661,599	101 %	1,537,997	93 %	8 %
	France	115,120	81 %	111,831	79 %	3 %	452,936	85 %	472,722	89 %	(4)%
	United States	413,242	84 %	430,748	99 %	(4)%	1,713,418	94 %	1,294,013	98 %	32 %
	Chile[6]	219,332	82 %	—	— %	— %	277,238	81 %	—	— %	— %
	Subtotal	**1,188,675**	**88 %**	**980,344**	**96 %**	**21 %**	**4,105,191**	**94 %**	**3,304,732**	**94 %**	**24 %**
SOLAR	Ontario	13,431	112 %	13,020	107 %	3 %	32,323	105 %	33,236	107 %	(3)%
	United States	324,960	90 %	315,572	92 %	3 %	815,599	86 %	691,390	85 %	18 %
	Chile[4,5]	60,792	80 %	47,851	94 %	27 %	192,253	84 %	129,170	94 %	49 %
	Subtotal	**399,183**	**89 %**	**376,443**	**93 %**	**6 %**	**1,040,175**	**86 %**	**853,796**	**87 %**	**22 %**
TOTAL PRODUCTION[1]		**2,736,471**	**91 %**	**2,290,086**	**89 %**	**19 %**	**7,896,968**	**92 %**	**6,472,058**	**91 %**	**22 %**
Innergex's share of production of joint venture and associates		257,368	105 %	248,559	102 %	4 %	446,453	99 %	705,134	96 %	(37)%
PRODUCTION PROPORTIONATE[1,2]		**2,993,839**	**92 %**	**2,538,645**	**90 %**	**18 %**	**8,343,421**	**93 %**	**7,177,192**	**92 %**	**16 %**

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 September 30, 2022, was 91% of LTA. The result is mostly explained by lower production at the facilities in British Columbia due to drier weather, mechanical issues at the Foard City facility and lower irradiation at the Phoebe facility in Texas, combined with below-average wind regimes in 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 92% of LTA.

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

Production for the nine-month period ended September 30, 2022, was 92% 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 and the unfavourable impact of the intermittent curtailment required by the distribution network in Texas for the Phoebe facility, combined with 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 94% of LTA. Innergex's share of production of joint ventures and associates was 99% of LTA, translating into a Production Proportionate at 93% 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 difference 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
Salvador Battery Storage (Chile)	Storage	100	Note [4]	—	—	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).

Updated status for the following projects:

Hale Kuawehi:

- Major construction is still suspended until there is more certainty around module pricing and the battery supplier design.
- Contractor completed civil works including site grading, fencing, and site access roads.
- PPA repricing discussions are currently taking place.
- Project COD in Q3 2024.

Innavik:

- Derivation structure concreting completed.
- Powerhouse superstructure and envelope completed.
- Both turbines are installed and aligned and generator installation will begin shortly.
- Footing of the dam sheet is underway and the dam is planned to be completed in Q4 2022.
- Spillway concrete work is in progress and is planned to be completed in Q4 2022.
- Transmission line structures are already installed and hardware and cable installation should be completed in Q4 2022.
- Conversion of the Office municipal d'habitation Kativik ("OMHK") residences has started and is progressing as per schedule. Conversion of the other residences will start in 2023.
- Project COD in Q1 2023.

Salvador Battery Storage

- Construction started on June 9, 2022.
- Inverters arrived and are stored on site.
- Installation of foundations is complete.
- COD might be delayed to Q3 2023 due to delay in battery delivery, but the corporation is expected to be compensated by liquidated damage.

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

2- OVERVIEW OF OPERATIONS | Development Activities

Innergex owns a portfolio of Development Projects with a gross installed capacity of approximately 730.2 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
Boswell Springs (Wyoming, U.S.)	Wind	329.8	30	2024
Paeahu (Hawaii, U.S.)	Solar	15.0 [2]	25	— [3]
Kahana (Hawaii, U.S.)	Solar	20.0 [2]	25	— [3]
Barbers Point (Hawaii, U.S.)	Solar	15.0 [2]	25	— [3]
Palomino (Ohio, U.S.)	Solar	200.0	15	2025
San Andrés Battery Storage (Chile)	Storage	— [4]	—	2023

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) for Paeahu, 20 MW/80 MWh (4 hours) for Kahana and 15 MW/60 MWh (4 hours) for Barbers Point.
3. Project schedule under revision.
4. Battery storage capacity of 35 MW/175 MWh (5 hours).

In 2019, the Corporation secured 125 MW of solar panels qualifying approximately 650 MW of future solar projects eligible for the investment tax credit program ("ITC"), that could be used for some current and future development projects.

Updated status from the previous quarter for the following projects:

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

Boswell Springs
- Final approval for PPA from Wyoming Public Utility Commission (PUC) is underway.
- Permitting completed.
- The project is eligible to receive 100% of Production Tax Credits ("PTCs").

Paeahu
- The Corporation intends to submit a PPA price increase and an updated construction schedule to the utility for consideration, pending a positive ruling on the contested case for the CUP.

Kahana
- The Corporation submitted a PPA price increase and an updated construction schedule to the utility for consideration. Approval is pending.

Barbers Point
- The Corporation submitted a PPA price increase and an updated construction schedule to the utility for consideration. Negotiations are underway.

Palomino
- Secured panels for the Project through Module Supply Agreement.
- The Ohio Power Siting Board Staff Report of Investigation hearing scheduled for November - permit issuance expected Q1 2023.
- Interconnection Services Agreement (ISA) expected Q1 2023.

San Andrés
- Environmental Permit request submitted and under evaluation.
- Local building permits under preparation.
- Site preparation expected to start in Q4 2022.

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

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
Subtotal	3,503	33	2,400	6	—	—	5,903	39
UNITED STATES								
Solar	573	6	450	2	520	2	1,543	10
Wind	—	—	400	1	—	—	400	1
Green hydrogen[2]	5	1	—	—	—	—	5	1
Subtotal	578	7	850	3	520	2	1,948	12
FRANCE								
Solar	—	—	—	—	85	1	85	1
Wind	49	3	92	5	149	8	290	16
Subtotal	49	3	92	5	234	9	375	17
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	4,263	48	3,342	14	908	12	8,513	74
Changes from Q2 2022	+698	—	+320	+2	—	—	+1,018	+2

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 Q2 2022, two existing projects in the Early Stage saw an increase in capacity and one new project was added to Early Stage in Canada. Two Early Stage projects were abandoned in the United States and one new project was added to Mid Stage. In France, one new project was added to Mid Stage. In Chile, one new project was added in Early Stage.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS

	Three months ended September 30				Nine months ended September 30					
	2022	2021	Change		2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized[3]	Change	
Revenues	258,389	184,564	73,825	40 %	666,858	544,820	(54,967)	489,853	177,005	36 %
Operating expenses	54,593	45,395	9,198	20 %	145,177	106,551	—	106,551	38,626	36 %
General and administrative expenses	14,824	11,512	3,312	29 %	39,503	32,285	—	32,285	7,218	22 %
Prospective projects expenses	7,814	5,135	2,679	52 %	17,622	17,658	—	17,658	(36)	— %
Adjusted EBITDA[1]	181,158	122,522	58,636	48 %	464,556	388,326	(54,967)	333,359	131,197	39 %
Adjusted EBITDA margin[1]	70.1 %	66.4 %			69.7 %	71.3 %	(3.2)%	68.1 %		
Finance costs	90,418	66,519	23,899	36 %	233,978	184,838	—	184,838	49,140	27 %
Other net income	(6,571)	(33,827)	27,256	81 %	(45,683)	(55,056)	—	(55,056)	9,373	17 %
Depreciation and amortization	82,953	59,838	23,115	39 %	242,297	177,892	—	177,892	64,405	36 %
Impairment of long-term assets	—	30,660	(30,660)	(100)%	—	36,974	—	36,974	(36,974)	(100)%
Share of (earnings) loss of joint ventures and associates:[2]										
Share of (earnings) loss, before impairment charges	(15,654)	(14,311)	(1,343)	(9)%	(14,668)	78,071	(64,197)	13,874	(28,542)	(206)%
Share of impairment charges	—	—	—	— %	—	112,609	—	112,609	(112,609)	(100)%
Change in fair value of financial instruments	211	15,366	(15,155)	(99)%	80,767	107,533	(72,060)	35,473	45,294	128 %
Income tax expense (recovery)	8,821	21,741	(12,920)	(59)%	6,405	(63,398)	17,071	(46,327)	52,732	114 %
Net earnings (loss)	20,980	(23,464)	44,444	189 %	(38,540)	(191,137)	64,219	(126,918)	88,378	70 %
Net earnings (loss) attributable to:										
Owners of the parent	23,269	(16,398)	39,667	242 %	(36,318)	(189,457)	64,219	(125,238)	88,920	71 %
Non-controlling interests	(2,289)	(7,066)	4,777	68 %	(2,222)	(1,680)	—	(1,680)	(542)	(32)%
	20,980	(23,464)	44,444	189 %	(38,540)	(191,137)	64,219	(126,918)	88,378	70 %
Basic and diluted net earnings (loss) per share from continuing operations attributable to owners ($)	0.11	(0.10)			(0.20)	(1.09)	0.36	(0.73)		

1. Adjusted EBITDA and Adjusted EBITDA Margin are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
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 six months ended September 30, 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.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Hydroelectric Segment

	Three months ended September 30			Nine months ended September 30		
Hydroelectric Segment	2022	2021	Change	2022	2021	Change
Production (MWh)	1,148,613	933,299	23 %	2,751,602	2,313,530	19 %
LTA (MWh)	1,218,783	1,151,138	6 %	3,013,749	2,585,769	17 %
Revenues (in $M)	109,533	78,414	40 %	275,563	180,910	52 %
Operating, general and administrative expenses	23,599	15,868	49 %	66,622	40,847	63 %
Adjusted EBITDA (in $M)[1]	85,934	62,546	37 %	208,941	140,063	49 %
Adjusted EBITDA Margin[1]	78.5 %	79.8 %		75.8 %	77.4 %	
PROPORTIONATE[1]						
Production Proportionate (MWh)	1,378,690	1,153,856	19 %	3,112,093	2,739,021	14 %
Revenues Proportionate (in $M)	134,065	101,885	32 %	313,711	223,950	40 %
Adjusted EBITDA Proportionate (in $M)	107,487	82,924	30 %	239,451	173,581	38 %
Adjusted EBITDA Margin Proportionate	80.2 %	81.4 %		76.3 %	77.5 %	

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 September 30, 2022, the increase of 40% in Revenues in the hydroelectric segment compared with the same period last year is mainly explained by the acquisition of Curtis Palmer completed on October 25, 2021, and of the remaining 50% interest in Energía Llaima on July 9, 2021, for which results are now included in Innergex's consolidated revenues and by higher production at the facilities in British Columbia due to the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line in 2021. The increase of 49% in Operating, general and administrative expenses is explained by higher maintenance costs at some facilities in British Columbia, higher expenses following the Curtis Palmer Acquisition and from the Chilean facilities following the acquisition of the remaining 50% interest in Energía Llaima. As a result, the Adjusted EBITDA[1] increased by 37% to $85.9 million. The Adjusted EBITDA Margin[1] was down from 79.8% to 78.5%, mainly explained by lower contributions from facilities in Ontario and British Columbia due to lower revenues and higher operating expenses.

For the three-month period ended September 30, 2022, the increase of 32% in Revenues Proportionate[1] in the hydroelectric segment was partly explained by the joint ventures' and associates' Revenues, which increased compared to the same period last year due to a higher contribution from the Toba Montrose and Umbata Falls facilities. 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] increased by 30% to $107.5 million.

For the nine-month period ended September 30, 2022, the increase of 52% in Revenues in the hydroelectric segment compared with the same period last year is mainly explained by the acquisition of Curtis Palmer completed on October 25, 2021, and of the remaining 50% interest in Energía Llaima on July 9, 2021, for which results are now included in Innergex's consolidated revenues. The increase is also explained by the BC Hydro Curtailment Payment and by higher production at the facilities in British Columbia due to the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line in 2021. The increase of 63% 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 Curtis Palmer Acquisition and from the Chilean facilities following the acquisition of the remaining 50% interest in Energía Llaima. As a result, the Adjusted EBITDA[1] increased by 49% to $208.9 million. The Adjusted EBITDA Margin[1] was down from 77.4% to 75.8%, mainly explained by lower contribution from the facilities in British Columbia due to higher operating expenses, partly offset by the Curtis Palmer Acquisition, for which margins are higher.

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

For the nine-month period ended September 30, 2022, the increase of 40% in Revenues Proportionate[1] in the hydroelectric segment, mainly stemming from the increase in consolidated revenues, was partly offset by the joint ventures' and associates' Revenues, which decreased compared with the same period last year due to a lower contribution from the Chilean facilities 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 38% to $239.5 million.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Wind Segment

Wind Segment	Three months ended September 30			Nine months ended September 30				
	2022	2021	Change	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	1,188,675	980,344	21 %	4,105,191	3,304,732	—	3,304,732	24 %
LTA (MWh)	1,352,090	1,024,347	32 %	4,348,497	3,503,914	—	3,503,914	24 %
Revenues (in $M)	101,970	70,678	44 %	293,505	259,506	(16,801)	242,705	21 %
Operating, general and administrative expenses	25,288	25,096	1 %	63,929	56,665	—	56,665	13 %
Adjusted EBITDA (in $M)[1]	76,682	45,582	68 %	229,576	202,841	(16,801)	186,040	23 %
Adjusted EBITDA Margin[1]	75.2 %	64.5 %		78.2 %	78.2 %	(9.2)%	76.7 %	
PROPORTIONATE[1]								
Production Proportionate (MWh)	1,215,966	1,008,346	21 %	4,191,153	3,578,835	—	3,578,835	17 %
Revenues Proportionate (in $M)	115,661	84,603	37 %	352,681	352,857	(57,107)	295,750	19 %
Adjusted EBITDA Proportionate (in $M)	89,384	58,620	52 %	285,914	291,234	(57,107)	234,127	22 %
Adjusted EBITDA Margin Proportionate	77.3 %	69.3 %		81.1 %	82.5 %	(10.1)%	79.2 %	

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 nine-month period ended September 30, 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 September 30, 2022, Revenues increased by 44% in the wind power generation segment compared with the same period last year, mainly due to the commissioning of the Griffin Trail facility on July 26, 2021 and the acquisition of the Aela wind farms on June 9, 2022 and to increased revenues from the new PPAs at some facilities in France. The increase was partly offset by lower revenues from lower wind regimes at some facilities in France combined with unfavourable exchange rates. The increase of 1% in Operating, general and administrative expenses is explained by higher expenses following the acquisition of the Aela wind farms partly offset by reduced operating costs at some facilities in the United States. As a result, the Adjusted EBITDA[1] increased by 68% to $76.7 million, compared with the same period last year. The Adjusted EBITDA Margin[1] was up from 64.5% to 75.2%, mainly explained by the commissioning of the Griffin Trail facility and by lower operating costs at the Foard City facility.

For the three-month period ended September 30, 2022, the increase of 37% in Revenues Proportionate[1] was explained by the consolidated facilities partly offset by the decrease of Production Tax Credits ("PTCs") generated by the wind farms mostly due to the lower production from the Foard City facility. There were no significant impacts of 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 52% to $89.4 million.

For the nine-month period ended September 30, 2022, Revenues increased by 21% 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 commissioning of the Griffin Trail facility on July 26, 2021, the acquisition of the Aela wind farms, completed on June 9, 2022 and to higher production from the facilities in Quebec. The increase was partly offset by lower revenues from lower production at some facilities in France combined with unfavourable exchange rates. The increase of 13% in Operating, general and administrative expenses is due mainly to the acquisition of the Aela wind farms and the commissioning of the Griffin Trail facility. This increase was partly offset by lower variable expenses following lower revenues at the Foard City facility and lower expenses in France due to unfavourable exchange rates. As a result, the Adjusted EBITDA[1] increased by 23% to

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

$229.6 million, compared with the same period last year, for which the Adjusted EBITDA[1] was normalized to exclude the February 2021 Texas Events. The Adjusted EBITDA Margin[1] was up from 76.7% to 78.2%, on a normalized basis, explained by higher margins in Quebec and higher revenues at the Griffin Trail facility.

For the nine-month period ended September 30, 2022, the increase of 19% 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 our 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 reason stated above. As a result, the Adjusted EBITDA Proportionate[1] increased by 22% to $285.9 million, on a normalized basis.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Solar Segment

	Three months ended September 30			Nine months ended September 30				
Solar Segment	2022	2021	Change	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	399,183	376,443	6 %	1,040,175	853,796	—	853,796	22 %
LTA (MWh)	447,056	404,765	10 %	1,205,873	986,076	—	986,076	22 %
Revenues (in $M)	46,886	35,472	32 %	97,790	104,404	(38,166)	66,238	48 %
Operating, general and administrative expenses	6,446	5,695	13 %	17,552	11,109	—	11,109	58 %
Adjusted EBITDA (in $M)[1]	40,440	29,777	36 %	80,238	93,295	(38,166)	55,129	46 %
Adjusted EBITDA Margin[1]	86.3 %	83.9 %		82.1 %	89.4 %	(10.4)%	83.2 %	
PROPORTIONATE[1]								
Production Proportionate (MWh)	399,183	376,443	6 %	1,040,175	859,336	—	859,336	21 %
Revenues Proportionate (In $M)	46,886	35,472	32 %	97,790	105,289	(38,166)	67,123	46 %
Adjusted EBITDA Proportionate (In $M)	40,440	29,777	36 %	80,238	93,849	(38,166)	55,683	44 %
Adjusted EBITDA Margin Proportionate	86.3 %	83.9 %		82.1 %	89.1 %	(10.3)%	83.0 %	

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 nine months ended September 30, 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 September 30, 2022, Revenues increased by 32% in the solar power generation segment compared with the same period last year, due mainly to the higher selling prices at the Phoebe facility and to the San Andrés Acquisition completed on January 28, 2022. This increase was partly offset by lower average selling prices at the Salvador facilities. The increase of 13% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Hillcrest facility and the San Andrés Acquisition. As a result, the Adjusted EBITDA[1] increased by 36% to $40.4 million, compared with the same period last year. The Adjusted EBITDA Margin[1] was up from 83.9% to 86.3%, mainly explained by the higher revenues at the Phoebe facility and the lower operating expenses at the Salvador facility.

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

For the nine-month period ended September 30, 2022, Revenues increased 48% 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, to the San Andrés Acquisition completed 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 58% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Hillcrest facility on October 31, 2021, and the acquisition of the San Andrés and Pampa Elvira facilities. As a result, the Adjusted EBITDA[1] increased by 46% to $80.2 million, compared with the same period last year, for which the Adjusted EBITDA was normalized to exclude the February 2021 Texas Events. The Adjusted EBITDA Margin[1] was down from 83.2% to 82.1%, on a normalized basis, mainly explained by the Hillcrest commissioning, for which margins are lower and partly offset by the San Andrés Acquisition, for which margins are higher, and higher revenues at the Phoebe facility. The Adjusted EBITDA Margin[1] was down from 83.2% to 82.1%, on a normalized basis, mainly explained by the Hillcrest commissioning, for which margins are lower and partly offset by the San Andrés Acquisition, for which margins are higher, and higher revenues at the Phoebe facility.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Consolidated Margin

Innergex believes these indicators are important, as they provide management and the reader with additional information about Innergex's operating performance. For more information, please refer to the Non-IFRS Measures section of this MD&A.

For the three-month period ended on September 30, 2022, on a consolidated basis, the Adjusted EBITDA[1] was up 48% from $122.5 million to $181.2 million, compared with the same period last year. The increase stems mainly from the increase in the cumulative segmented Adjusted EBITDA[1] as explained in the previous sections. The Adjusted EBITDA Margin[1,2] was up from 66.4% to 70.1%. This increase is mainly explained by the commissioning of the Griffin Trail facility on July 26, 2021 and lower operating expenses at the Foard City facility.

For the three-month period ended on September 30, 2022, the Adjusted EBITDA Proportionate Margin[1] was up from 70.3% to 72.6%. This increase is explained by higher Adjusted EBITDA margin[1,2] and by higher PTCs earned from the Griffin Trail facility following its commissioning on July 26, 2021.

For the nine-month period ended September 30, 2022, on a consolidated basis, the Adjusted EBITDA[1] was up 39% from $333.4 million to $464.6 million, compared with the same period last year, for which the Adjusted EBITDA was normalized to exclude the February 2021 Texas Events. The increase stems mainly from the increase in the cumulative segmented Adjusted EBITDA[1] as explained in the previous sections. The Adjusted EBITDA Margin[2], on a normalized basis to exclude the February 2021 Texas Events, was up from 68.1% to 69.7%. This increase is mainly explained by the BC Hydro Curtailment Payment and the Curtis Palmer Acquisition, for which margins are higher. The increase is partly offset by certain facilities recently commissioned and acquired, for which margins are lower.

For the nine-month period ended September 30, 2022, the Adjusted EBITDA Proportionate Margin[1], on a normalized basis to exclude the February 2021 Texas Events, was up from 70.8% to 72.2%. This increase is explained by higher PTCs earned from the Griffin Trail facility following its commissioning on July 26, 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.
[2] The Adjusted EBITDA Margin is a measure of Adjusted EBITDA as a percentage of revenues.

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

Net earnings of $21.0 million ($0.11 net earnings per share - basic and diluted) for the three-month period ended September 30, 2022, compared with a net loss of $23.5 million ($0.10 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 $44.4 million increase in net earnings mainly stems from:

- a favourable $15.2 million change in the fair value of financial instruments, mainly related to the favourable change in foreign exchange forward curves in 2022 compared with the same period last year;
- a $30.7 million decrease in impairment of long-term assets following the impairment charges recognized in 2021 on the Phoebe solar facility and to a minority equity investment in France; and
- a $12.9 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, partly offset by an increase in income tax expense due to a favorable change in fair value of financial instruments and the non-recognition of some tax losses in Chile.

These items were partly offset by:
- a $27.3 million decrease in other net income, 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;
- a $23.9 million increase in finance costs mainly related to the Aela acquisition, the Griffin Trail and Hillcrest facilities, and an increase in inflation compensation interests on the Harrison Hydro real return bonds; and
- a $23.1 million increase in depreciation and amortization, mainly attributable to Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissionings in 2021.

Net loss of $38.5 million ($0.20 net loss per share - basic and diluted) for the nine-month period ended September 30, 2022, compared with a net loss of $191.1 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 $152.6 million decrease in net loss mainly stems from:

- a $205.3 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);
  - 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; and
- a favourable $26.8 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 curves in 2022 compared with the same period last year, partly offset by the increase in merchant power curves for the Phoebe power hedge; and
- a $37.0 million decrease in impairment of long-term assets following 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.

These items were partly offset by:
- a $69.8 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 to the accelerated tax depreciation taken in 2021 on the Griffin Trail facility;
- a $64.4 million increase in depreciation and amortization, mainly attributable to the Energía Llaima, Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissionings in 2021; and
- a $49.1 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.

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

The Adjusted Net (Loss) Earnings[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) Earnings[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) Earnings[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 September 30		Nine months ended September 30	
	2022	2021	2022	2021
Revenues	258,389	184,564	666,858	489,853
Expenses:				
Operating expenses	54,593	45,395	145,177	106,551
General and administrative expenses	14,824	11,512	39,503	32,285
Prospective project expenses	7,814	5,135	17,622	17,658
Adjusted EBITDA[1]	181,158	122,522	464,556	333,359
Finance costs	90,418	66,519	233,978	184,838
Other net income	(4,531)	(32,694)	(42,469)	(53,175)
Depreciation and amortization	82,953	59,838	242,297	177,892
Share of earnings of joint ventures and associates	(15,244)	(14,070)	(12,891)	(12,151)
Realized loss on power hedges	23,861	1,139	35,920	1,230
Income tax expense	4,708	29,885	13,297	31,702
Adjusted Net (Loss) Earnings[1]	(1,007)	11,905	(5,576)	3,023

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.

Adjusted Net Loss[1] of $1.0 million for the three-month period ended September 30, 2022, compared with an Adjusted Net Earnings[1] of $11.9 million for the corresponding period in 2021.

The $12.9 million increase in Adjusted Net Loss[1] mainly stems from:

- a $28.2 million decrease in other net income, 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;
- a $23.9 million increase in finance costs mainly related to the Aela acquisition, the Griffin Trail and Hillcrest facilities, and an increase in inflation compensation interests on the Harrison Hydro real return bonds;
- a $23.1 million increase in depreciation and amortization, mainly attributable to the Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissionings in 2021; and
- an unfavourable $22.7 million realized change in the fair value of financial instruments, mainly related to higher merchant prices in 2022 affecting the Phoebe power hedge.

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

- a $25.2 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, partly offset by the non-recognition of some tax losses in Chile.

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

Adjusted Net Loss[1] of $5.6 million for the nine-month period ended September 30, 2022, compared with an Adjusted Net Earnings[1] of $3.0 million for the corresponding period in 2021.

The $8.6 million increase in Adjusted Net Loss[1] mainly stems from:
- a $64.4 million increase in depreciation and amortization**,** mainly attributable to the Energía Llaima, Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissionings in 2021;
- a $49.1 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 $34.7 million realized change in the fair value of financial instruments, mainly related to the higher merchant prices in 2022 affecting the Phoebe power hedge; and
- a $10.7 million decrease in other net income, 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.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, these items were partly offset by:
- an $18.4 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 $2.3 million to non-controlling interests for the three-month period ended September 30, 2022, compared with an attribution of loss of $7.1 million for the corresponding period in 2021.

The $4.8 million decrease in loss attributed to non-controlling interests for the three-month period ended September 30, 2022, is mainly due to:
- a favourable movement in the unrealized change in the fair value of derivative financial instruments in Innergex Europe; and
- a higher allocation of earnings to the non-controlling interests of Kwoiek Creek largely due to a higher production, compared with 2021 which was affected by a wildfire that damaged the facility's transmission line.

These items were partly offset by:

- the loss allocated to the non-controlling interests in Innergex HQI USA following the Curtis Palmer Acquisition in the fourth quarter of 2021; and
- 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.

Attribution of loss of $2.2 million to non-controlling interests for the nine-month period ended September 30, 2022, compared with an attribution of loss of $1.7 million for the corresponding period in 2021.

The $0.5 million increase in loss attributed to non-controlling interests for the nine-month period ended September 30, 2022, is mainly due to:
- 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.

These items were partly offset by:
- a favourable movement in the unrealized change in the fair value of derivative financial instruments in Innergex Europe;
- a higher allocation of earnings to the non-controlling interests of Kwoiek Creek largely due to a higher production, compared with 2021 which was affected by a wildfire that damaged the facility's transmission line; and
- a contractual increase in the percentage of allocation to the non-controlling interests of Mesgi'g Ugju's'n.

4- CAPITAL AND LIQUIDITY | Capital Structure

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

	As at September 30, 2022	As at December 31, 2021
Equity[1]		
Common shares[2]	3,549,593	3,580,388
Preferred shares[3]	94,970	109,080
Non-controlling interests	254,959	267,568
	3,899,522	3,957,036
Long-term loans and borrowings[1]		
Corporate revolving credit facility	551,098	398,758
Other corporate debt	305,000	295,000
Project-level debt	4,200,800	3,562,380
Tax Equity financing	460,487	455,967
Convertible debentures	282,073	280,258
Deferred financing costs	(82,949)	(67,928)
	5,716,509	4,924,435
	9,616,031	8,881,471

1.Common and preferred shares are presented at their fair value as at September 30, 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 September 30, 2022, and December 31, 2021, multiplied by the prevailing share price of $17.39 (2021 - $18.60) at the close of markets.
3.Consists of the number of preferred shares outstanding as at September 30, 2022, and December 31, 2021, multiplied by the prevailing share price of $14.55 and $22.75 (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 a distribution allocated to the non-controlling interests during the quarter.

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 September 30, 2022 (4.62% as at December 31, 2021).

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

Credit Agreements – Material Financial and Non-Financial Conditions

As at September 30, 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 are 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 September 30, 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.

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

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	46.5	4.9	99.00 %	5.00 %
Griffin Trail[1,2]	2021	2031	210.6	29.6	5.2	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 1.3707. 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 1.3707. 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 ($123.9 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.

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

4- CAPITAL AND LIQUIDITY | Financial Position

As at	September 30, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	216,851	166,266
Restricted cash	53,532	61,659
Investment tax credits recoverable	1,298	1,200
Other current assets	232,247	159,552
Total current assets	503,928	388,677
Non-current assets		
Property, plant and equipment	6,203,188	5,513,392
Intangible assets	1,292,767	1,043,994
Investments in joint ventures and associates	140,562	133,398
Goodwill	58,886	60,858
Other non-current assets	405,500	255,749
Total non-current assets	8,100,903	7,007,391
Total assets	8,604,831	7,396,068
LIABILITIES		
Current liabilities	628,829	733,527
Non-current liabilities		
Long-term loans and borrowings	5,346,685	4,411,239
Other non-current liabilities	975,123	890,622
Total non-current liabilities	6,321,808	5,301,861
Total liabilities	6,950,637	6,035,388
SHAREHOLDERS' EQUITY		
Equity attributable to owners	1,399,235	1,093,112
Non-controlling interests	254,959	267,568
Total shareholders' equity	1,654,194	1,360,680
	8,604,831	7,396,068

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

Working Capital Items

As at September 30, 2022, working capital[1] was negative at $124.9 million, from negative $344.9 million in 2021, mainly explained by:

- Current assets amounted to $503.9 million as at September 30, 2022, an increase of $115.3 million compared with December 31, 2021, mainly due to a $50.6 million increase in cash and cash equivalents (see the "Cash Flow" section of this MD&A for more information), accounts receivable and prepaid and other, attributable mainly to the Aela and San Andrés acquisitions.

- Current liabilities amounted to $628.8 million as at September 30, 2022, a decrease of $104.7 million compared with December 31, 2021, mainly due to a $143.4 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 the upcoming maturity on February 6, 2023, and 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] to be sufficient to meet its needs. As at September 30, 2022, the Corporation had $950.0 million in revolving term credit facility and had drawn $551.1 million as cash advances, while $55.5 million had been used to issue letters of credit, leaving $343.4 million available.

Non-Current Assets

Non-current assets amounted to $8,100.9 million as at September 30, 2022, an increase of $1,093.5 million compared with December 31, 2021. The increase is mainly due to an aggregate addition of $921.2 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 $82.5 million, net of the ITC recoverable recognized against the project construction costs of Hale Kuawehi. 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, partly offset by a strengthening of the Canadian dollar against the Euro.

These items were partly offset by depreciation and amortization of $242.3 million, 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.

Non-Current Liabilities

Non-current liabilities amounted to $6,321.8 million as at September 30, 2022, an increase of $1,019.9 million compared with December 31, 2021. The increase is mainly due to a $935.4 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 towards 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 $77.2 million increase in deferred tax liabilities, largely related to a favourable change in the fair value of the derivative financial instruments.

These items were partly offset by the classification of the subordinated unsecured term loan as current due to its upcoming maturity on February 6, 2023. The scheduled principal repayments also contributed to decreasing the non-current portion of long-term loans and borrowings.

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

Shareholders' Equity

As at September 30, 2022, Shareholders' equity increased by $293.5 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 $249.2 million, partly offset by the dividends declared on common and preferred shares totalling $114.4 million, and $39.1 million in distributions to non-controlling interests.

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 $75.9 million as at September 30, 2022, from a net liability of $59.4 million as at December 31, 2021. The favourable unrealized change in fair value relates mainly to the interest hedging derivatives, favourably impacted by an upward shift in 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.

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[2] 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

[2] 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.

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.

Off-Balance-Sheet Arrangements

As at September 30, 2022, the Corporation had issued letters of credit totalling $293.4 million, including $55.5 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 | Cash Flows

	Three months ended September 30		Nine months ended September 30			
	2022	2021	2022	2021	February 2021 Texas Events (9 days)	2021 Normalized[1]
OPERATING ACTIVITIES						
Cash flows from operating activities	184,126	80,052	336,612	189,661	17,093	206,754
FINANCING ACTIVITIES						
Cash flows from financing activities	(128,209)	6,348	221,545	47,849	—	47,849
INVESTING ACTIVITIES						
Cash flows used in investing activities	(63,311)	(66,421)	(507,998)	(220,971)	—	(220,971)
Effects of exchange rate changes on cash and cash equivalents	(676)	1,426	426	(2,954)	—	(2,954)
Net change in cash and cash equivalents	(8,070)	21,405	50,585	13,585	17,093	30,678
Cash and cash equivalents, beginning of period	224,921	153,645	166,266	161,465	—	161,465
Cash and cash equivalents, end of period	216,851	175,050	216,851	175,050	17,093	192,143

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 September 30, 2022, cash flows from operating activities totalled $184.1 million, compared with $80.1 million in the same period last year. The increase relates primarily to the contribution from the Curtis Palmer, San Andrés and Aela acquisitions, the Hillcrest and Griffin Trail commissionings, and the realized gain on financial instruments following the settlement of the interest rate swaps as part of Innergex's refinancing of the non-recourse debt of its Chilean facilities, partly offset by an increase in realized losses on the Phoebe power hedge due to increased merchant prices.

For the nine-month period ended September 30, 2022, cash flows from operating activities totalled $336.6 million, compared with $189.7 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 the interest rate swaps as part of Innergex's refinancing of the non-recourse debt of its Chilean facilities and the net unfavourable impact of the February 2021 Texas Events 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 Aela Acquisition, and by the distribution received from Energía Llaima in the second quarter of 2021.

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

Cash Flows from Financing Activities

For the three-month period ended September 30, 2022, cash flows used in financing activities totalled $128.2 million, compared with cash flows of $6.3 million in the same period last year. The decrease stems mainly from the proceeds received from the public offering of common shares and the Hydro-Québec Private Placement in 2021 (nil during the same period of 2022). The decrease in cash flows from financing activities was partly offset by a $82.1 million net repayment of long-term loans and borrowings in 2022, mainly explained by lower scheduled debt principal repayments. This compares with net repayments of $224.8 million in 2021, following the public offering of common shares and the Hydro-Québec Private Placement, partly offset by net draws made toward the construction of the Griffin Trail wind facility.

For the nine-month period ended September 30, 2022, cash flows from financing activities totalled $221.5 million, compared with $47.8 million in the same period last year. The increase stems mainly from the net $184.1 million increase in long-term loans and borrowings in 2022, mainly explained by the San Andrés and Aela acquisitions and the additions to property, plant and equipment. This compares with a decrease of $99.2 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 September 30, 2022, cash flows used in investing activities remained largely unchanged, at $63.3 million, compared with $66.4 million in the same period last year. This is explained by the payment of the withholding tax to the Chilean tax authorities on behalf of the seller related to the Aela acquisitions, mostly offset by a decrease in additions to property plant and equipment and project development costs.

For the nine-month period ended September 30, 2022, cash flows used in investing activities totalled $508.0 million, compared with $221.0 million in the same period last year. The increase in cash flows from investing activities is mainly due to the consideration paid toward the San Andrés and Aela acquisitions, partly offset by the additions to property, plant and equipment of the Griffin Trail and Hillcrest facilities in 2021.

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

Free Cash Flow and Payout Ratio calculation[1]	Trailing twelve months ended September 30			
	2022	2021	February 2021 Texas Events (9 days)[5]	2021 Normalized[5]
Cash flows from operating activities[6]	412,447	267,354	17,093	284,447
Add (Subtract) the following items:				
Changes in non-cash operating working capital items	24,525	(2,754)	—	(2,754)
Maintenance capital expenditures, net of proceeds from disposals	(9,936)	(5,455)	—	(5,455)
Scheduled debt principal payments	(167,578)	(155,072)	—	(155,072)
Free Cash Flow attributed to non-controlling interests[2]	(39,811)	(13,787)	—	(13,787)
Dividends declared on Preferred shares	(5,632)	(5,710)	—	(5,710)
Chile portfolio refinancing - hedging impact[3]	765	—	—	—
Add (subtract) the following specific items[4]:				
Realized loss on contingent considerations	—	3,568	—	3,568
Realized (gain) loss on termination of interest rate swaps	(72,053)	2,885	—	2,885
Acquisition, integration and restructuring costs	17,224	1,640	—	1,640
Realized gain on the Phoebe basis hedge	(955)	(1,458)	(1,304)	(2,762)
Free Cash Flow[5]	158,996	91,211	15,789	107,000
Dividends declared on common shares	144,862	129,005	—	129,005
Payout Ratio[5]	91 %	141 %	(20)%	121 %
Adjust for the following items:				
Prospective projects expenses	27,331			21,266
Adjusted Free Cash Flow	186,327			128,266
Adjusted Payout Ratio	78 %			96 %

1. Free Cash Flow, Adjusted Free Cash Flow, Payout Ratio and Adjusted Payout Ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.
2. The portion of Free Cash Flow attributed to non-controlling interests is subtracted, regardless of whether an actual distribution to non-controlling interests is made, in order to reflect the fact that such distributions may not occur in the period they are generated.
3. The Free Cash Flow for the trailing twelve months ended September 30, 2022 excludes the gains realized 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.
4. 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.
5. For the trailing twelve months ended September 30, 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.
6. Cash flows from operating activities for the trailing twelve months ended September 30, 2022 include the one-time BC Hydro Curtailment Payment received during the first quarter of 2022.

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

Free Cash Flow

For the trailing twelve months ended September 30, 2022, the Corporation generated Free Cash Flow[1] of $159.0 million, compared with $91.2 million for the corresponding period last year (Normalized Free Cash Flow[1,2] of $107.0 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 $52.0 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; and
- an increase in revenues from the the BC Hydro Curtailment Payment.

These items were partly offset by:

- an increase in debt principal payments stemming from the Energía Llaima Acquisition in the third quarter of 2021 and the beginning of debt principal repayment for the Upper Lillooet/Boulder Creek and Hillcrest project loans;
- an increase in Free Cash Flow attributed to non-controlling interests, stemming mainly from the Curtis Palmer Acquisition; 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 trailing twelve months ended September 30, 2022, the dividends on common shares declared by the Corporation amounted to 91% of Free Cash Flow[1], compared with 141% 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 121% 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		
	November 4, 2022	September 30, 2022	December 31, 2021
Number of common shares	204,132,833	204,116,917	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 November 4, 2022, and since September 30, 2022, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 15,916 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at September 30, 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 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.

2022 Third Quarter (in thousands of Canadian dollars, except as noted and amounts per share)

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 September 30				Nine months ended September 30			
	2022		2021		2022		2021	
	($/share)	Total	($/share)	Total	($/share)	Total	($/share)	Total
Dividends declared on common shares[1]	0.180	36,741	0.180	34,703	0.5400	110,213	0.5400	97,580
Dividends declared on Series A Preferred Shares	0.2028	689	0.2028	689	0.6083	2,068	0.6083	2,068
Dividends declared on Series C Preferred Shares	0.3594	719	0.3594	719	1.0781	2,156	1.0781	2,156

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 January 16, 2023:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
November 7, 2022	December 31, 2022	January 16, 2023	$0.180	$0.202750	$0.359375

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

5- 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 Margin, Adjusted EBITDA Proportionate, Adjusted EBITDA Margin 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 Margin and 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.

References in this document to "Adjusted EBITDA Margin" are to Adjusted EBITDA divided by revenues. References in this document to "Adjusted EBITDA Margin Proportionate" are to Adjusted EBITDA Proportionate, divided by Revenues Proportionate.

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. Adjusted EBITDA Margin and Adjusted EBITDA Margin Proportionate are used by investors to understand the relative weight of certain jurisdictions, which are subject to various competitive and energy pricing environments, to the Corporation’s and its reportable segments’ operating performance. 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, Adjusted EBITDA Proportionate, Adjusted EBITDA Margin, and Adjusted EBITDA Margin 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 September 30, 2022				Three months ended September 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	258,389	27,884	10,339	296,612	184,564	26,698	10,698	221,960
Net earnings (loss)	20,980	—	—	20,980	(23,464)	—	—	(23,464)
Income tax expense	8,821	—	—	8,821	21,741	—	—	21,741
Finance costs	90,418	4,495	—	94,913	66,519	4,536	—	71,055
Depreciation and amortization	82,953	4,227	—	87,180	59,838	4,245	—	64,083
Impairment of long-term assets	—	—	—	—	30,660	—	—	30,660
EBITDA	203,172	8,722	—	211,894	155,294	8,781	—	164,075
Other net expense (income), before PTCs	3,768	(46)	—	3,722	(23,129)	(136)	—	(23,265)
Production tax credits ("PTCs")	(10,339)	—	10,339	—	(10,698)	—	10,698	—
Share of earnings of joint ventures and associates	(15,654)	15,654	—	—	(14,311)	14,311	—	—
Change in fair value of financial instruments	211	(414)	—	(203)	15,366	(238)	—	15,128
Adjusted EBITDA	181,158	23,916	10,339	215,413	122,522	22,718	10,698	155,938
Adjusted EBITDA Margin	70.1 %	85.8 %		72.6 %	66.4 %	85.1 %		70.3 %

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

	Nine months ended September 30, 2022				Nine months ended September 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	666,858	49,171	48,153	764,182	544,820	99,662	37,614	682,096
Net loss	(38,540)	—	—	(38,540)	(191,137)	—	—	(191,137)
Income tax expenses (recovery)	6,405	—	—	6,405	(63,398)	(31)	—	(63,429)
Finance costs	233,978	13,395	—	247,373	184,838	18,841	—	203,679
Depreciation and amortization	242,297	12,646	—	254,943	177,892	18,810	—	196,702
Impairment of long-term assets	—	—	—	—	36,974	112,609	—	149,583
EBITDA	444,140	26,041	—	470,181	145,169	150,229	—	295,398
Other net expense (income), before PTCs	2,470	(235)	—	2,235	(23,476)	1,734	—	(21,742)
Production tax credits ("PTCs")	(48,153)	—	48,153	—	(31,580)	(6,034)	37,614	—
Share of (earnings) loss of joint ventures and associates	(14,668)	14,668	—	—	190,680	(190,680)	—	—
Change in fair value of financial instruments	80,767	(1,779)	—	78,988	107,533	129,602	—	237,135
Adjusted EBITDA	464,556	38,695	48,153	551,404	388,326	84,851	37,614	510,791
Adjusted EBITDA Margin	69.7 %	78.7 %		72.2 %	71.3 %	85.1 %		74.9 %

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

Adjusted Net (Loss) Earnings

References to "Adjusted Net (Loss) Earnings" 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) Earnings 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) Earnings should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section for reconciliation of the Adjusted Net (Loss) Earnings.

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

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Net earnings (loss)	20,980	(23,464)	(38,540)	(191,137)
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	(300)	(178)	(1,305)	20,603
Unrealized portion of the change in fair value of financial instruments	48,026	15,572	116,523	34,253
Impairment of long-term assets	—	30,660	—	36,974
Realized (gain) loss on termination of interest rate swaps	(71,676)	—	(71,676)	2,885
Realized gain on the Phoebe basis hedge	—	(1,345)	—	(1,591)
Realized gain on foreign exchange forward contracts	(2,040)	(1,133)	(3,214)	(1,881)
Income tax expense (recovery) related to above items	4,003	(8,207)	(7,364)	(89,678)
Adjusted Net (Loss) Earnings	(1,007)	11,905	(5,576)	3,023

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

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

	Three months ended September 30						Nine months ended September 30					
	2022			2021			2022			2021		
	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS
Revenues	258,389	—	258,389	184,564	—	184,564	666,858	—	666,858	544,820	(54,967)	489,853
Operating expenses	54,593	—	54,593	45,395	—	45,395	145,177	—	145,177	106,551	—	106,551
General and administrative expenses	14,824	—	14,824	11,512	—	11,512	39,503	—	39,503	32,285	—	32,285
Prospective projects expenses	7,814	—	7,814	5,135	—	5,135	17,622	—	17,622	17,658	—	17,658
Adjusted EBITDA	181,158	—	181,158	122,522	—	122,522	464,556	—	464,556	388,326	(54,967)	333,359
Finance costs	90,418	—	90,418	66,519	—	66,519	233,978	—	233,978	184,838	—	184,838
Other net income	(6,571)	2,040	(4,531)	(33,827)	1,133	(32,694)	(45,683)	3,214	(42,469)	(55,056)	1,881	(53,175)
Depreciation and amortization	82,953	—	82,953	59,838	—	59,838	242,297	—	242,297	177,892	—	177,892
Impairment of long-term assets	—	—	—	30,660	(30,660)	—	—	—	—	36,974	(36,974)	—
Share of (earnings) losses of joint ventures and associates	(15,654)	410	(15,244)	(14,311)	241	(14,070)	(14,668)	1,777	(12,891)	190,680	(202,831)	(12,151)
Change in fair value of financial instruments	211	23,650	23,861	15,366	(14,227)	1,139	80,767	(44,847)	35,920	107,533	(106,303)	1,230
Income tax (recovery) expense	8,821	(4,113)	4,708	21,741	8,144	29,885	6,405	6,892	13,297	(63,398)	95,100	31,702
Net earnings (loss)	20,980	(21,987)	(1,007)	(23,464)	35,369	11,905	(38,540)	32,964	(5,576)	(191,137)	194,160	3,023

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

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.

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

	As at	
	September 30, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets[1]		
Canada	3,271,348	3,390,029
United States	2,452,965	2,301,353
Chile	1,450,292	423,856
France	701,201	801,752
	7,875,806	6,916,990

1. Includes the investments in joint ventures and associates.

6- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Revenues

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Revenues				
Canada	121,982	109,990	341,245	312,706
United States	76,143	43,516	182,434	145,840
Chile	44,290	15,414	83,744	21,430
France	15,974	15,644	59,435	64,844
	258,389	184,564	666,858	544,820

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

6- ADDITIONAL CONSOLIDATED INFORMATION | Historical Quarterly Financial Information

	Three months ended							
(in millions of dollars, unless otherwise stated)	Sept 30, 2022	June 30, 2022	March 31, 2022	Dec 31, 2021	Sept 30, 2021	June 30, 2021	March 31, 2021	Dec 31, 2020
Production (MWh)	2,736,471	2,855,891	2,304,600	2,583,157	2,290,086	2,396,027	1,785,947	2,186,961
Revenues	258.4	219.7	188.7	202.4	184.6	170.6	189.7	167.9
Operating, general and administrative and prospective projects expenses	77.2	66.9	58.2	65.1	62.1	47.9	46.6	50.1
Adjusted EBITDA[1]	181.2	152.9	130.5	137.3	122.5	122.7	143.1	117.8
Net earnings (loss)	21.0	(24.6)	(34.9)	5.7	(23.5)	50.2	(217.9)	11.9
Net earnings (loss) attributable to owners of the parent	23.3	(25.2)	(34.4)	(2.3)	(16.4)	41.1	(214.2)	11.9
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.11	(0.13)	(0.18)	(0.02)	(0.10)	0.23	(1.24)	0.06
Dividends declared on common shares	36.7	36.7	36.7	34.6	34.7	31.4	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

All amounts are in thousands of Canadian dollars, unless otherwise indicated.

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:

		Nine months ended September 30, 2021		
		As presented	Impacts from the February 2021 Texas Events (9 days)	Normalized
1	Revenues	544,820	(54,967)	489,853
	Adjusted EBITDA[1]	388,326	(54,967)	333,359
2	Change in fair value of financial instruments	(107,533)	72,060	(35,473)
3	Share of losses (earnings) of joint ventures and associates	(190,680)	64,197	(126,483)
	(Loss) Earnings before income tax	(254,535)	81,290	(173,245)

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**.

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

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

	Nine months ended September 30, 2021				
	Hydro	Wind	Solar	Unallocated	Total
Revenues	180,910	259,506	104,404	—	544,820
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Revenues[2]	180,910	242,705	66,238	—	489,853
Revenues Proportionate[1]	223,950	352,857	105,289	—	682,096
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Revenues Proportionate[1,2]	223,950	295,750	67,123	—	586,823
Adjusted EBITDA[1]	140,063	202,841	93,295	(47,873)	388,326
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Adjusted EBITDA[1,2]	140,063	186,040	55,129	(47,873)	333,359
Adjusted EBITDA Proportionate[1]	173,581	291,234	93,849	(47,873)	510,791
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Adjusted EBITDA Proportionate[1,2]	173,581	234,127	55,683	(47,873)	415,518

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:

		Trailing twelve months ended September 30, 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	264,600	17,093	281,693
2	Realized loss on the Phoebe basis hedge	(1,458)	(1,304)	(2,762)
	Free Cash Flow[1]	91,211	15,789	107,000
	Dividends declared on common shares	129,005	—	129,005
	Payout Ratio[1]	141 %	(20)%	121 %

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.

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

(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.

7- ACCOUNTING POLICIES AND DISCLOSURE 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 unaudited condensed interim consolidated financial statements.

7- ACCOUNTING POLICIES AND DISCLOSURE CONTROLS | Disclosure Controls and Procedures

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 certified that they 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.

During the period beginning on July 1, 2022, and ended on September 30, 2022, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

The President and Chief Executive Officer and the Chief Financial Officer have also limited the scope of the Corporation's design of DC&P and ICFR to exclude the controls, policies and procedures of the Curtis/Palmer Hydroelectric Company LP and Aela Generación S.A. and Aela Energía SpA (together "Aela") (collectively "entities excluded from the Corporation's control policies and procedures"). The evaluation of the design and the operating effectiveness of the DC&P and ICFR for these entities will be completed in the 12 months following their dates of acquisition. A summary of the financial information about the entities excluded is presented in the "Entities Excluded from The Corporation’s Control Policies and Procedures" section of this MD&A.

7- ACCOUNTING POLICIES AND DISCLOSURE CONTROLS | Entities excluded from the Corporation's control, policies and procedures

As stated in the "Disclosure Controls and Procedures" section of this MD&A, the scope of the Corporation's design of DC&P and ICFR exclude the controls, policies and procedures of the Curtis/Palmer Hydroelectric Company LP and Aela Generación S.A. and Aela Energía SpA (together "Aela"). The following tables present a summary of the entities excluded from the Corporation's control policies and procedures:

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

	For the nine-month period ended September 30, 2022[1]
Revenues	66,669
Net loss	(36,209)
Total comprehensive loss	(36,209)

1. Includes the combined results of Aela for a 113-day period ended September 30, 2022.

Summary Statement of Financial Position

	As at September 30, 2022
Current assets	77,817
Non-current assets	1,745,378
	1,823,195
Current liabilities	68,365
Non-current liabilities	1,172,975
Equity	581,855
	1,823,195

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

8- 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 1 - Highlights of the MD&A for the three- and six-month periods ended June 30, 2022 for details regarding the assumptions used with respect to the 2022 growth targets and to Section 5 - Outlook of the Annual Report for the 2020-2025 Strategic Plan.

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 or pay a 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.

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

	Notes	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Revenues		258,389	184,564	666,858	544,820
Expenses					
Operating		54,593	45,395	145,177	106,551
General and administrative		14,824	11,512	39,503	32,285
Prospective projects		7,814	5,135	17,622	17,658
Earnings before the following:		181,158	122,522	464,556	388,326
Depreciation	9	57,801	44,027	166,812	133,184
Amortization		25,152	15,811	75,485	44,708
Impairment of long-term assets		—	30,660	—	36,974
Earnings before the following:		98,205	32,024	222,259	173,460
Finance costs	4	90,418	66,519	233,978	184,838
Other net income	5	(6,571)	(33,827)	(45,683)	(55,056)
Share of (earnings) losses of joint ventures and associates:					
Share of (earnings) losses, before impairment charges		(15,654)	(14,311)	(14,668)	78,071
Share of impairment charges		—	—	—	112,609
Change in fair value of financial instruments	7 b)	211	15,366	80,767	107,533
Earnings (loss) before income tax		29,801	(1,723)	(32,135)	(254,535)
Income tax expense (recovery)		8,821	21,741	6,405	(63,398)
Net earnings (loss)		20,980	(23,464)	(38,540)	(191,137)
Net earnings (loss) attributable to:					
Owners of the parent		23,269	(16,398)	(36,318)	(189,457)
Non-controlling interests		(2,289)	(7,066)	(2,222)	(1,680)
		20,980	(23,464)	(38,540)	(191,137)
Earnings (loss) per share attributable to owners:					
Basic net earnings (loss) per share ($)	8	0.11	(0.10)	(0.20)	(1.09)
Diluted net earnings (loss) per share ($)	8	0.11	(0.10)	(0.20)	(1.09)

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

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Notes	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Net earnings (loss)		20,980	(23,464)	(38,540)	(191,137)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:					
Foreign currency translation differences for foreign operations		88,439	23,126	107,205	246
Change in fair value of financial instruments designated as net investment hedges	7	5,429	(699)	11,340	4,126
Change in fair value of financial instruments designated as cash flow hedges	7	16,203	10,966	218,127	70,212
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges		220	789	9,275	5,569
Related deferred income tax		(2,863)	(3,972)	(58,227)	(22,112)
Other comprehensive income		107,428	30,210	287,720	58,041
Total comprehensive income (loss)		128,408	6,746	249,180	(133,096)
Total comprehensive income (loss) attributable to:					
Owners of the parent		111,770	13,521	222,701	(133,290)
Non-controlling interests		16,638	(6,775)	26,479	194
		128,408	6,746	249,180	(133,096)

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

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	September 30, 2022	December 31, 2021
ASSETS			
Current assets			
Cash and cash equivalents		216,851	166,266
Restricted cash		53,532	61,659
Accounts receivable		148,825	117,906
Derivative financial instruments	7	29,282	17,024
Investment tax credits recoverable	9	1,298	1,200
Prepaid and other		54,140	24,622
Total current assets		503,928	388,677
Non-current assets			
Property, plant and equipment	9	6,203,188	5,513,392
Intangible assets		1,292,767	1,043,994
Project development costs		68,174	70,829
Investments in joint ventures and associates		140,562	133,398
Derivative financial instruments	7	149,006	39,917
Deferred tax assets		76,091	50,484
Goodwill		58,886	60,858
Other long-term assets		112,229	94,519
Total non-current assets		8,100,903	7,007,391
Total assets		8,604,831	7,396,068
LIABILITIES			
Current liabilities			
Accounts payable and other payables		223,535	174,364
Derivative financial instruments	7	30,872	41,315
Current portion of long-term loans and borrowings and other liabilities		374,422	517,848
Total current liabilities		628,829	733,527
Non-current liabilities			
Derivative financial instruments	7	71,523	75,064
Long-term loans and borrowings		5,346,685	4,411,239
Other liabilities		425,227	414,343
Deferred tax liabilities		478,373	401,215
Total non-current liabilities		6,321,808	5,301,861
Total liabilities		6,950,637	6,035,388
SHAREHOLDERS' EQUITY			
Equity attributable to owners		1,399,235	1,093,112
Non-controlling interests		254,959	267,568
Total shareholders' equity		1,654,194	1,360,680
Total liabilities and shareholders' equity		8,604,831	7,396,068

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Equity attributable to owners								
For the nine-month period ended September 30, 2022	Common share capital account	Contributed surplus	Preferred shares	Convertible debentures	Deficit	Accumulated other comprehensive loss	Total	Non-controlling interests	Total shareholders' equity
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	—	—	—	—	(36,318)	—	(36,318)	(2,222)	(38,540)
Other comprehensive income	—	—	—	—	—	259,019	259,019	28,701	287,720
Total comprehensive (loss) income	—	—	—	—	(36,318)	259,019	222,701	26,479	249,180
Common shares issued on public offering (Note 11)	172,506	—	—	—	—	—	172,506	—	172,506
Issuance fees (net of $1,978 of deferred income tax)	(5,399)	—	—	—	—	—	(5,399)	—	(5,399)
Common shares issued on private placement (Note 11)	37,275	—	—	—	—	—	37,275	—	37,275
Issuance fees (net of $11 of deferred income tax)	(33)	—	—	—	—	—	(33)	—	(33)
Common shares issued through dividend reinvestment plan	1,058	—	—	—	—	—	1,058	—	1,058
Reduction of capital on common shares (Note 11)	(560,532)	560,532	—	—	—	—	—	—	—
Buyback of common shares	(4,417)	—	—	—	—	—	(4,417)	—	(4,417)
Share-based payments and Performance Share Plan	—	2,625	—	—	—	—	2,625	—	2,625
Shares vested - Performance Share Plan	2,114	(4,883)	—	—	—	—	(2,769)	—	(2,769)
Shares purchased - Performance Share Plan	(3,266)	279	—	—	—	—	(2,987)	—	(2,987)
Dividends declared on common shares (Note 11)	—	—	—	—	(110,213)	—	(110,213)	—	(110,213)
Dividends declared on preferred shares (Note 11)	—	—	—	—	(4,224)	—	(4,224)	—	(4,224)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(39,088)	(39,088)
Balance September 30, 2022	242	2,581,093	131,069	2,819	(1,524,383)	208,395	1,399,235	254,959	1,654,194

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the nine-month period ended September 30, 2021	Equity attributable to owners								
	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	—	—	—	—	(189,457)	—	(189,457)	(1,680)	(191,137)
Other comprehensive income	—	—	—	—	—	56,167	56,167	1,874	58,041
Total comprehensive (loss) income	—	—	—	—	(189,457)	56,167	(133,290)	194	(133,096)
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)	(6,272)	—	—	—	—	—	(6,272)	—	(6,272)
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	3,074	—	—	—	—	—	3,074	—	3,074
Buyback of common shares	(3,414)	—	—	—	—	—	(3,414)	—	(3,414)
Share-based payments and Performance Share Plan	—	1,554	—	—	—	—	1,554	—	1,554
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)	274	—	—	—	—	(2,348)	—	(2,348)
Dividends declared on common shares (Note 11)	—	—	—	—	(97,580)	—	(97,580)	—	(97,580)
Dividends declared on preferred shares (Note 11)	—	—	—	—	(4,224)	—	(4,224)	—	(4,224)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(13,270)	(13,270)
Balance September 30, 2021	366,348	2,021,923	131,069	2,819	(1,335,223)	(55,529)	1,131,407	57,991	1,189,398

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three months ended September 30		Nine months ended September 30	
		2022	2021	2022	2021
OPERATING ACTIVITIES	Notes				
Net earnings (loss)		20,980	(23,464)	(38,540)	(191,137)
Items not affecting cash:					
Depreciation and amortization		82,953	59,838	242,297	177,892
Impairment of long-term assets		—	30,660	—	36,974
Share of (earnings) losses of joint ventures and associates		(15,654)	(14,311)	(14,668)	190,680
Unrealized portion of change in fair value of financial instruments	7	48,026	15,572	116,523	34,253
Production tax credits and tax attributes allocated to tax equity investors	5	(11,906)	(31,418)	(49,606)	(53,367)
Other		4,707	(117)	5,160	796
Finance costs	4	90,418	66,519	233,978	184,838
Finance costs paid	12 b)	(55,861)	(39,832)	(158,468)	(130,993)
Distributions received from joint ventures and associates		7,616	8,139	17,088	21,636
Income tax expense (recovery)		8,821	21,741	6,405	(63,398)
Income tax recovered (paid)		(1,501)	(1,141)	(423)	(4,223)
Effect of exchange rate fluctuations		(2,655)	818	(4,735)	1,039
		175,944	93,004	355,011	204,990
Changes in non-cash operating working capital items	12 a)	8,182	(12,952)	(18,399)	(15,329)
		184,126	80,052	336,612	189,661
FINANCING ACTIVITIES					
Dividends paid on common and preferred shares		(37,905)	(34,363)	(111,278)	(95,529)
Distributions to non-controlling interests		(6,018)	(1,302)	(39,088)	(12,885)
Increase in long-term debt, net of deferred financing costs	12 c)	869,249	404,760	1,473,348	793,331
Repayment of long-term debt	12 c)	(951,393)	(629,518)	(1,289,275)	(892,525)
Payment of other liabilities		(2,249)	(1,156)	(4,360)	(3,465)
Net proceeds from issuance of common shares		—	267,830	202,371	267,830
Payment for buyback of common shares		—	—	(4,417)	(3,414)
Purchase of common shares under the Performance Share Plan		107	97	(2,987)	(2,348)
Payment of payroll withholding on exercise of stock options and Performance Share Plan		—	—	(2,769)	(3,146)
		(128,209)	6,348	221,545	47,849
INVESTING ACTIVITIES					
Business acquisitions, net of cash acquired	3	(21,657)	1,391	(418,042)	1,391
Change in restricted cash		(417)	(717)	10,749	(584)
Additions to property, plant and equipment, net		(39,495)	(62,812)	(76,882)	(204,081)
Additions to intangible assets		—	(8)	(22)	(8)
Additions to project development costs		(25)	(5,426)	(16,932)	(17,520)
Investments in joint ventures and associates		(2)	—	(334)	(65)
Proceeds from disposal of investment		530	—	530	—
Change in other long-term assets		(2,245)	1,151	(7,065)	(104)
		(63,311)	(66,421)	(507,998)	(220,971)
Effects of exchange rate changes on cash and cash equivalents		(676)	1,426	426	(2,954)
Net change in cash and cash equivalents		(8,070)	21,405	50,585	13,585
Cash and cash equivalents, beginning of period		224,921	153,645	166,266	161,465
Cash and cash equivalents, end of period		216,851	175,050	216,851	175,050

Additional information is presented in Note 12.

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

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

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") was incorporated under the *Canada Business Corporation Act* on October 25, 2002, and its shares and convertible debentures are listed on the Toronto Stock Exchange. The Corporation is a developer, acquirer, owner and operator of renewable power-generating 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 unaudited condensed interim consolidated financial statements were approved by the Board of Directors on November 7, 2022.

The Corporation's revenues are variable with each season and are normally at their highest in the second quarter and at their lowest in the first quarter. As a result, earnings of interim periods should not be considered as indicative of results for an entire year.

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

Statement of Compliance

These unaudited condensed interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). The condensed interim consolidated financial statements are in compliance with IAS 34, Interim Financial Reporting. Except as described below, the same accounting policies and methods of application as described in the Corporation's latest annual report have been used. However, these unaudited condensed interim consolidated financial statements do not include all disclosures required under IFRS and, accordingly, should be read in conjunction with the audited consolidated financial statements and the notes thereto included in the Corporation's latest annual report.

Basis of Measurement

The unaudited condensed interim consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

Functional Currency and Presentation Currency

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

2. SIGNIFICANT ACCOUNTING POLICIES

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 unaudited condensed interim 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 unaudited condensed interim consolidated financial statements.

3. 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 ($408,159), which includes a US$17,210 ($21,657) payable to the Chilean tax authorities on behalf of the seller that remains outstanding as at June 30, 2022.

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	19,220	24,187
Prepaid and other	5,812	7,313
Property, plant and equipment	480,625	604,818
Intangible assets	220,763	277,808
Derivative financial instruments	5,218	6,567
Deferred tax assets	22,962	28,896
Accounts payable and other payables	(11,167)	(14,053)
Long-term loans and borrowings	(380,235)	(478,488)
Other liabilities	(49,371)	(62,129)
Deferred tax liability	(7,567)	(9,522)
Net assets acquired	324,348	408,159

The acquisition gave rise to transaction costs of $11,245 which were expensed as incurred in other net income in the consolidated statements of earnings (loss).

The investment 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 $25,228 and $20,376, respectively for the 113-day period ended September 30, 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 September 30, 2022 would have been $39,311 higher and $303 higher, respectively.

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

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 ($36,067). The facility is expected to produce a gross long-term average of approximately 118.9 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	2,692	3,422
Accounts receivable	499	634
Prepaid and other	526	669
Property, plant and equipment	19,802	25,173
Intangible assets	10,562	13,426
Accounts payable and other payables	(727)	(924)
Other liabilities	(2,361)	(3,001)
Deferred tax liability	(2,621)	(3,332)
Net assets acquired	28,372	36,067

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 investment 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 $6,165 and $3,239, respectively for the 245-day period ended September 30, 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 September 30, 2022 would have been $501 higher and $449 lower, respectively.

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

4. FINANCE COSTS

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Interest expense on long-term corporate and project loans	60,279	44,210	156,031	128,169
Interest expense on tax equity financing	7,547	8,522	22,479	18,617
Interest expense on convertible debentures	3,409	3,409	10,209	10,214
Inflation compensation interest	6,242	3,898	17,542	9,415
Amortization of financing fees	5,302	2,115	11,141	5,767
Accretion expenses on other liabilities	1,856	1,384	5,264	3,975
Interest on lease liabilities	1,990	1,125	5,149	3,159
Accretion of long-term loans and borrowings	132	(25)	373	249
Other	3,661	1,881	5,790	5,273
	90,418	66,519	233,978	184,838

5. OTHER NET INCOME

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Production tax credits income	(10,339)	(10,698)	(48,153)	(31,580)
Tax attributes allocated to tax equity investors income	(1,567)	(20,720)	(1,453)	(21,787)
Realized gain on foreign exchange	(4,695)	(13)	(7,950)	(604)
Acquisition, integration and restructuring costs	6,912	841	13,505	841
Loss on disposal of property, plant and equipment	5,165	201	5,171	496
Loss on repayment of loans	—	—	—	1,317
Professional and other fees - February 2021 Texas Events	—	130	—	1,308
Realized loss on contingent considerations	—	—	—	547
Other income, net	(2,047)	(3,568)	(6,803)	(5,594)
	(6,571)	(33,827)	(45,683)	(55,056)

6. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

Disposition of Shannon

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

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

7. 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 3)	—	6,567	—	—	6,567
Unrealized portion of change in fair value recognized in earnings (loss) [2]	38,523	(58,723)	(81,221)	(15,102)	(116,523)
Change in fair value recognized in other comprehensive income (loss)	11,340	220,814	(2,687)	—	229,467
Amortization of accumulated other comprehensive income recognized in revenue	—	—	2,687	—	2,687
Net foreign exchange differences	—	2,669	(4,638)	15,102	13,133
As at September 30, 2022	52,348	92,845	(69,300)	—	75,893

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 7 b) for a reconciliation to the change in fair value recognized in earnings (loss).

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

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Unrealized portion of change in fair value of financial instruments	48,026	15,572	116,523	34,253
Realized portion of financial instruments:				
Realized loss on the power hedges	23,861	1,139	35,920	71,986
Realized gain on the interest rate swaps	(71,676)	—	(71,676)	2,885
Realized gain on Phoebe basis hedge	—	(1,345)	—	(1,591)
Change in fair value of financial instruments	211	15,366	80,767	107,533

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

8. EARNINGS (LOSS) PER SHARE

Basic	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Net earnings (loss) attributable to owners of the parent	23,269	(16,398)	(36,318)	(189,457)
Dividends declared on preferred shares	(1,408)	(1,408)	(4,224)	(4,224)
Net earnings (loss) attributable to common shareholders	21,861	(17,806)	(40,542)	(193,681)
Weighted average number of common shares	203,522,521	182,691,797	201,264,532	177,043,601
Basic net earnings (loss) per share ($)	0.11	(0.10)	(0.20)	(1.09)

Diluted	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Net earnings (loss) attributable to common shareholders	21,861	(17,806)	(40,542)	(193,681)
Diluted weighted average number of common shares	204,159,644	182,691,797	201,264,532	177,043,601
Diluted net earnings (loss) per share ($)	0.11	(0.10)	(0.20)	(1.09)

	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Instruments that are excluded from the dilutive elements:				
Stock options	—	265,570	284,769	265,570
Shares held in trust related to the Performance Share Plan	—	541,261	592,257	541,261
Convertible debentures	13,604,473	13,604,473	13,604,473	13,604,473
	13,604,473	14,411,304	14,481,499	14,411,304

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

9. 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]	8,262	4,091	1,033	897	73,072	5,368	92,723
Investment tax credits [2]	—	—	—	—	(8,535)	—	(8,535)
Business acquisitions (Note 3)	53,217	—	551,592	25,169	—	13	629,991
Transfer of assets upon commissioning	—	—	—	—	(6,840)	6,840	—
Transfer from project development costs	—	—	—	—	25,034	—	25,034
Reclassification	—	—	(1,292)	—	(59)	1,351	—
Dispositions	—	(504)	(5,831)	—	—	(322)	(6,657)
Other changes	4,859	296	(55,712)	(14,653)	—	(21)	(65,231)
Net foreign exchange differences	13,480	41,509	68,346	55,854	11,412	779	191,380
As at September 30, 2022	264,918	2,640,172	3,450,100	886,888	166,961	59,072	7,468,111
Accumulated depreciation							
As at January 1, 2022	(16,801)	(391,093)	(549,980)	(115,531)	—	(22,609)	(1,096,014)
Depreciation [3]	(5,459)	(39,757)	(94,478)	(22,583)	—	(4,686)	(166,963)
Dispositions	—	23	725	—	—	300	1,048
Net foreign exchange differences	(641)	(1,502)	5,260	(5,953)	—	(158)	(2,994)
As at September 30, 2022	(22,901)	(432,329)	(638,473)	(144,067)	—	(27,153)	(1,264,923)
Carrying amounts as at September 30, 2022	242,017	2,207,843	2,811,627	742,821	166,961	31,919	6,203,188

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

1. The financing costs related to a specific project financing are entirely capitalized to the specific property, plant and equipment. Financing costs related to the revolving credit facilities are capitalized for the portion of the financing actually used for a specific property, plant and equipment. Additions in the current period include $2,530 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 September 30, 2022, the current balance of investments tax credits recoverable, on the Hillcrest and the Hale Kuawehi projects, amounts to US$947 ($1,298), while the non current balance amounts to US$6,712 ($9,200).
3. An amount of $151 of the depreciation expense for the land leases is capitalized as a construction cost in facilities under construction.

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

10. LONG-TERM LOANS AND BORROWINGS

As at September 30, 2022, the Corporation and its subsidiaries have met all material financial and non-financial conditions related to their credit agreements.

The Corporation reclassified the $150,000 subordinated unsecured term loan as current, following the upcoming maturity on February 6, 2023.

a. 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.

b. Amendment to the revolving term credit facility

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 $950,000.

c. Aela Acquisition

As part of the Aela Acquisition, the Corporation assumed the facilities non-recourse debt, with an outstanding principal balance of US$380,194 ($489,918) at June 30, 2022, 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.

Refinancing of the Chilean project debts

On August 5, 2022, the Corporation completed the US$803,116 ($1,032,326) refinancing of the non-recourse debt of its portfolio of wholly owned assets in Chile 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)).

11. SHAREHOLDERS' CAPITAL

Common Shares

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 2,100,000 common shares in the share capital of the Corporation for cash proceeds of $37,275.

Buyback of common shares and preferred shares

During the nine-month period ended September 30, 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.

Equity-based compensation

a) Stock option plan

Granted
During the nine-month period ended September 30, 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 per share.

During the nine-month period ended September 30, 2022, 32,153 options were cancelled.

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:

Risk-free interest rate	1.78 %
Expected annual dividend per common share	$ 0.72
Expected life of options	6
Expected volatility	26.77 %

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

A compensation expense of $35 was recorded during the nine-month period ended September 30, 2022 with respect to the stock option plan.

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

Performance Share Plan

During the nine-month period ended September 30, 2022, 269,482 performance share rights vested.

In addition, 251,650 share rights were granted during the nine-month period ended September 30, 2022. The performance share rights vest on December 31, 2024.

Deferred Share Unit Plan

During the nine-month period ended September 30, 2022, 34,796 units were granted.

A compensation expense of $3,171 was recorded during the nine-month period ended September 30, 2022 with respect to the PSP and DSU plans.

Dividends

a) Dividend Declared

	Three months ended September 30				Nine months ended September 30			
	2022		2021		2022		2021	
	($/share)	Total	($/share)	Total	($/share)	Total	($/share)	Total
Dividends declared on common shares	0.180	36,741	0.180	34,703	0.5400	110,213	0.5400	97,580
Dividends declared on Series A preferred shares	0.2028	689	0.2028	689	0.6083	2,068	0.6083	2,068
Dividends declared on Series C preferred shares	0.3594	719	0.3594	719	1.0781	2,156	1.0781	2,156

Dividend declared subsequent to period end and not recognized at the end of the reporting period.

The following dividends will be paid by the Corporation on January 16, 2023:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
November 7, 2022	December 31, 2022	January 16, 2023	$ 0.180	$ 0.202750	$ 0.359375

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

12. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a) Changes in non-cash operating working capital items

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Accounts receivable	14,134	6,809	(4,577)	(22,058)
Prepaids and other	(884)	(5,756)	(19,471)	(11,979)
Accounts payable and other payables	(5,068)	(14,005)	5,649	18,708
	8,182	(12,952)	(18,399)	(15,329)

b) Additional information

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Finance costs paid relative to operating activities before interest on leases	(54,176)	(39,120)	(152,934)	(127,848)
Interest on leases paid relative to operating activities	(1,685)	(712)	(5,534)	(3,145)
Capitalized interest relative to investing activities	(454)	(496)	(1,036)	(2,506)
Capitalized interest on leases relative to investing activities	69	(632)	(283)	(1,815)
Total finance costs paid	(56,246)	(40,960)	(159,787)	(135,314)
Non-cash transactions:				
Change in unpaid property, plant and equipment	(7,047)	(4,308)	3,919	3,685
Investment tax credits	—	8,279	8,535	12,752
Change in other long-term assets	1,465	28	1,539	12
Change in unpaid project development costs	2,274	447	1,044	738
Remeasurement of other liabilities	(4,284)	(1,068)	(80,431)	(14,448)
Initial measurement of other liabilities	—	1,538	8,262	8,417
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
Unpaid distributions to non-controlling interests in subsidiaries	—	385	—	385
Common shares issued through dividend reinvestment plan	242	327	1,058	3,074
Common shares issued upon acquisition	—	89,437	—	89,437

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

c) Changes in liabilities arising from financing activities

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Changes in long-term loans and borrowings				
Long-term debt at beginning of period	5,662,005	4,879,345	4,924,435	4,813,881
Increase in long-term debt	887,711	404,760	1,497,992	793,331
Repayment of long-term debt	(951,393)	(629,518)	(1,289,275)	(892,525)
Payment of deferred financing costs	(18,462)	—	(24,644)	—
Business acquisitions (Note 3)	11,137	196,505	478,488	196,505
Investment tax credits	—	(29,617)	—	(29,617)
Tax attributes	(1,567)	(20,720)	(1,453)	(21,787)
Production tax credits	(10,339)	(10,698)	(48,153)	(31,580)
Other non-cash finance costs	19,214	14,294	51,485	38,148
Convertible debentures converted into common shares	—	—	—	(2,306)
Accretion of convertible debentures	623	541	1,814	1,884
Net foreign exchange differences	117,580	39,879	125,820	(21,163)
Long-term loans and borrowings at end of period	5,716,509	4,844,771	5,716,509	4,844,771

13. FINANCIAL RISK MANAGEMENT AND FAIR VALUE DISCLOSURES

Fair value disclosures

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 and basis hedges are calculated using a discounted cash flow model. The fair value calculation of power and basis hedges gives rise to measurement uncertainty as the power price curves are constructed using various methodologies and assumptions, which consider certain unobservable inputs. As at September 30, 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$27.90 to US$90.60 per MWh between October 1, 2022 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 $4.09 to US$73.21 per MWh between October 1, 2022 and December 31, 2030.

Further information is provided below with regard to the methodology for constructing the forward power price curves.

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

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 available as of the valuation date depending on a combination of observable exchange prices and over-the-counter broker quotes obtained through June 2031.

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$211,683 ($290,154) as at September 30, 2022.

Canadian Dollar Offered Rate ("CDOR")

While CDOR is not anticipated to immediately be retired, the administrator announced that it will cease publication of CDOR after June 28, 2024 for the remaining tenors. 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.

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.

14. 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.

[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 16, Segment Information, for more information.

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.

15. COVID-19

To combat the spread of the COVID-19, authorities in all regions where the Corporation operates have put in place restrictive measures for businesses. However, these measures have not impacted the Corporation in a material way to date, as electricity production has been deemed an essential service in every region where the Corporation operates. The renewable power production is sold mainly through power purchase agreements with public utilities and corporate entities with high credit ratings.

It is not excluded that current or future restrictive measures might have an adverse effect on the financial stability of the Corporation’s suppliers and other partners, or on the Corporation’s operating results, financial position, liquidity or capital expenditures. The issuance of permits and authorizations, negotiations and finalization of agreements with regard to development and acquisition projects, construction activities and procurement of equipment could be adversely impacted by the COVID-19 restrictive measures. The full potential impact of COVID-19 on the Corporation's business is unknown as it may continue for an extended period and will depend on future developments that are uncertain and cannot be predicted including, and without limitations, the duration and severity of the pandemic, the duration of government mitigation measures, the effectiveness of the actions taken to contain and treat the disease, and the length of time it takes for normal economic and operating conditions to resume.

16. 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.

Three months ended September 30, 2022				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	109,533	101,970	46,886	258,389
Innergex's share of revenues of joint ventures and associates	24,532	3,352	—	27,884
PTCs and Innergex's share of PTCs generated	—	10,339	—	10,339
Segment Revenues Proportionate	134,065	115,661	46,886	296,612
Segment Adjusted EBITDA	85,934	76,682	40,440	203,056
Innergex's share of Adjusted EBITDA of joint ventures and associates	21,553	2,363	—	23,916
PTCs and Innergex's share of PTCs generated	—	10,339	—	10,339
Segment Adjusted EBITDA Proportionate	107,487	89,384	40,440	237,311
Segment Adjusted EBITDA Margin	78.5 %	75.2 %	86.3 %	78.6 %

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

Nine months ended September 30, 2022				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	275,563	293,505	97,790	666,858
Innergex's share of revenues of joint ventures and associates	38,148	11,023	—	49,171
PTCs and Innergex's share of PTCs generated	—	48,153	—	48,153
Segment Revenues Proportionate	313,711	352,681	97,790	764,182
Segment Adjusted EBITDA	208,941	229,576	80,238	518,755
Innergex's share of Adjusted EBITDA of joint ventures and associates	30,510	8,185	—	38,695
PTCs and Innergex's share of PTCs generated	—	48,153	—	48,153
Segment Adjusted EBITDA Proportionate	239,451	285,914	80,238	605,603
Segment Adjusted EBITDA Margin	75.8 %	78.2 %	82.1 %	77.8 %

Nine months ended September 30, 2022	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	116,749	23,098	—	139,847
Property, plant and equipment acquired through business acquisitions (Note 3)	—	551,652	25,173	576,825
Acquisition of property, plant and equipment	4,283	2,239	1,329	7,851

1. Segment totals include only operating projects.

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

Three months ended September 30, 2021				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	78,414	70,678	35,472	184,564
Innergex's share of revenues of joint ventures and associates	23,471	3,227	—	26,698
PTCs and Innergex's share of PTCs generated	—	10,698	—	10,698
Segment Revenues Proportionate	101,885	84,603	35,472	221,960
Segment Adjusted EBITDA	62,546	45,582	29,777	137,905
Innergex's share of Adjusted EBITDA of joint ventures and associates	20,378	2,340	—	22,718
PTCs and Innergex's share of PTCs generated	—	10,698	—	10,698
Segment Adjusted EBITDA Proportionate	82,924	58,620	29,777	171,321
Segment Adjusted EBITDA Margin	79.8 %	64.5 %	83.9 %	74.7 %

Nine months ended September 30, 2021				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	180,910	259,506	104,404	544,820
Innergex's share of revenues of joint ventures and associates	43,040	55,737	885	99,662
PTCs and Innergex's share of PTCs generated	—	37,614	—	37,614
Segment Revenues Proportionate	223,950	352,857	105,289	682,096
Segment Adjusted EBITDA	140,063	202,841	93,295	436,199
Innergex's share of Adjusted EBITDA of joint ventures and associates	33,518	50,779	554	84,851
PTCs and Innergex's share of PTCs generated	—	37,614	—	37,614
Segment Adjusted EBITDA Proportionate	173,581	291,234	93,849	558,664
Segment Adjusted EBITDA Margin	77.4 %	78.2 %	89.4 %	80.1 %

Nine months ended September 30, 2021	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	115,093	21,852	—	136,945
Transfer of assets upon commissioning	—	357,502	—	357,502
Acquisition of property, plant and equipment	2,113	9,157	788	12,058

1. Segment totals include only operating projects.

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

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

	Three months ended September 30, 2022				Three months ended September 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	258,389	27,884	10,339	296,612	184,564	26,698	10,698	221,960
Net earnings (loss)	20,980	—	—	20,980	(23,464)	—	—	(23,464)
Income tax expense	8,821	—	—	8,821	21,741	—	—	21,741
Finance costs	90,418	4,495	—	94,913	66,519	4,536	—	71,055
Depreciation and amortization	82,953	4,227	—	87,180	59,838	4,245	—	64,083
Impairment of long-term assets	—	—	—	—	30,660	—	—	30,660
EBITDA	203,172	8,722	—	211,894	155,294	8,781	—	164,075
Other net income (expense), before PTCs	3,768	(46)	—	3,722	(23,129)	(136)	—	(23,265)
Production tax credits ("PTCs")	(10,339)	—	10,339	—	(10,698)	—	10,698	—
Share of (earnings) losses of joint ventures and associates	(15,654)	15,654	—	—	(14,311)	14,311	—	—
Change in fair value of financial instruments	211	(414)	—	(203)	15,366	(238)	—	15,128
Adjusted EBITDA	181,158	23,916	10,339	215,413	122,522	22,718	10,698	155,938
Unallocated expenses:								
General and administrative	14,084	—	—	14,084	10,248	—	—	10,248
Prospective projects	7,814	—	—	7,814	5,135	—	—	5,135
Segment Adjusted EBITDA	203,056	23,916	10,339	237,311	137,905	22,718	10,698	171,321
Segment Adjusted EBITDA Margin	78.6 %	85.8 %		80.0 %	74.7 %	85.1 %		77.2 %

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

	Nine months ended September 30, 2022				Nine months ended September 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	666,858	49,171	48,153	764,182	544,820	99,662	37,614	682,096
Net loss	(38,540)	—	—	(38,540)	(191,137)	—	—	(191,137)
Income tax expense (recovery)	6,405	—	—	6,405	(63,398)	(31)	—	(63,429)
Finance costs	233,978	13,395	—	247,373	184,838	18,841	—	203,679
Depreciation and amortization	242,297	12,646	—	254,943	177,892	18,810	—	196,702
Impairment of long-term assets	—	—	—	—	36,974	112,609	—	149,583
EBITDA	444,140	26,041	—	470,181	145,169	150,229	—	295,398
Other net income, before PTCs	2,470	(235)	—	2,235	(23,476)	1,734	—	(21,742)
Production tax credits ("PTCs")	(48,153)	—	48,153	—	(31,580)	(6,034)	37,614	—
Share of losses of joint ventures and associates	(14,668)	14,668	—	—	190,680	(190,680)	—	—
Change in fair value of financial instruments	80,767	(1,779)	—	78,988	107,533	129,602	—	237,135
Adjusted EBITDA	464,556	38,695	48,153	551,404	388,326	84,851	37,614	510,791
Unallocated expenses:								
General and administrative	36,577	—	—	36,577	30,215	—	—	30,215
Prospective projects	17,622	—	—	17,622	17,658	—	—	17,658
Segment Adjusted EBITDA	518,755	38,695	48,153	605,603	436,199	84,851	37,614	558,664
Segment Adjusted EBITDA Margin	77.8 %	78.7 %		79.2 %	80.1 %	85.1 %		81.9 %

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

Geographic segments

As at September 30, 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 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:

	Three months ended September 30		Nine months ended September 30	
	2022	2021	2022	2021
Revenues				
Canada	121,982	109,990	341,245	312,706
United States	76,143	43,516	182,434	145,840
Chile	44,290	15,414	83,744	21,430
France	15,974	15,644	59,435	64,844
	258,389	184,564	666,858	544,820

As at	September 30, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,271,348	3,390,029
United States	2,452,965	2,301,353
Chile	1,450,292	423,856
France	701,201	801,752
	7,875,806	6,916,990

1. Includes the investments in joint ventures and associates

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

17. SUBSEQUENT EVENTS

Acquisition of remaining interests in wind portfolio in France

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

Settlement of foreign exchange forward contracts

On October 5, 2022, as part of the financing of the acquisition of the remaining interests in wind portfolio in France, Innergex has monetized its Euro/CAD foreign exchange forward contracts for a total gain of $43,458 and has concurrently amended the Euro/CAD foreign exchange forward contracts for a total notional amount of $115,317, amortizing until 2043 and allowing conversion at a fixed rate of CAD 1.4838/Euro.

SHAREHOLDER INFORMATION

Head Office

1225 St-Charles West,
10th floor
Longueuil QC J4K 0B9
Tel. 450 928.2550
Fax 450 928.2544
innergex.com

Investor Relations
Jean Trudel
Chief Financial Officer
Tel. 450 928-2550 x1252
inverstorrelations@innergex.com

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

Series A Preferred Shares - TSX: INE.PR.A

Series C Preferred Shares - TSX: INE.PR.C

Convertible Debentures - TSX: INE.DB.B

Convertible Debentures - TSX: INE.DB.C

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