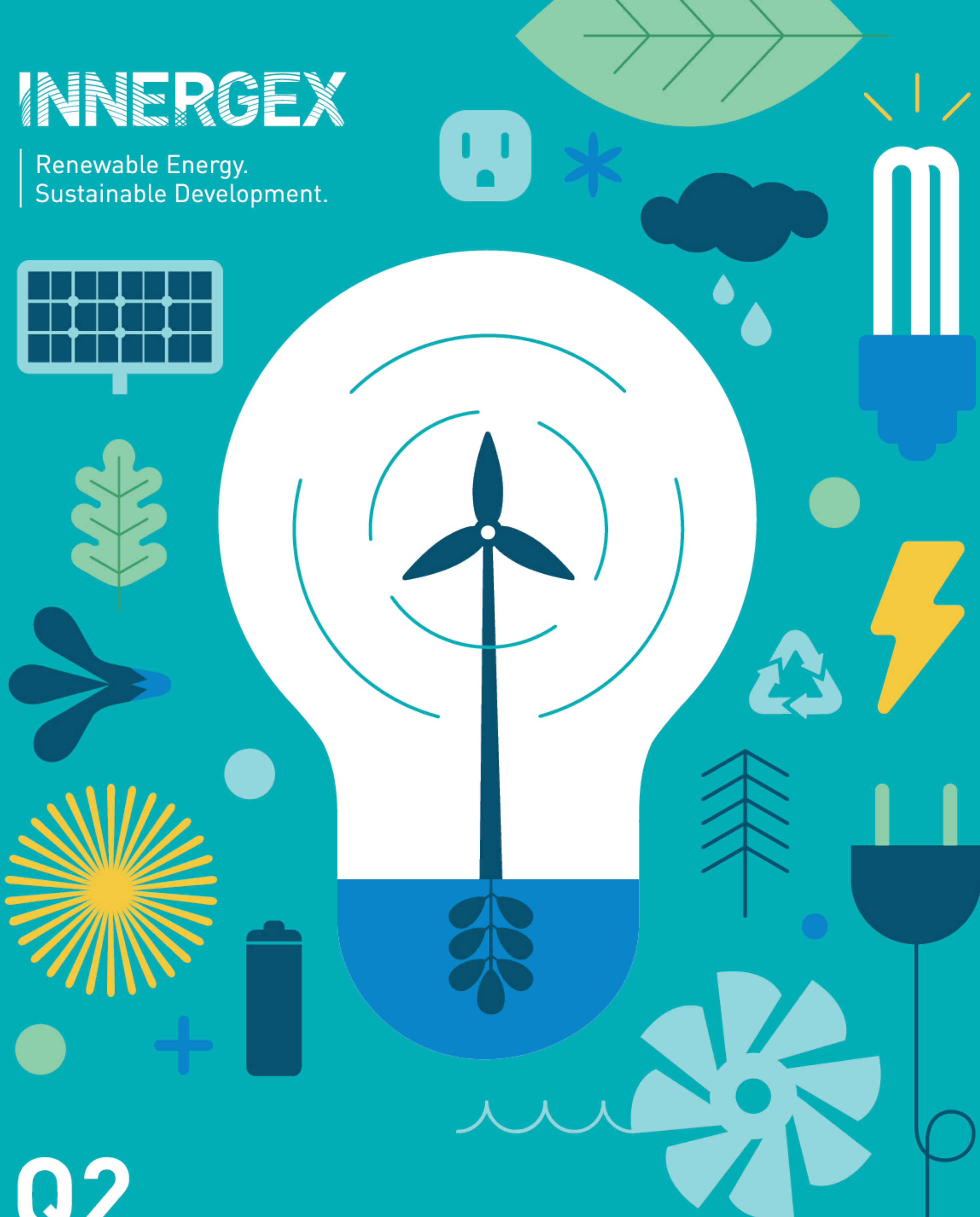
INNERGEX

Renewable Energy.
Sustainable Development.



Q2

Quarterly Report

For the Period Ended June 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

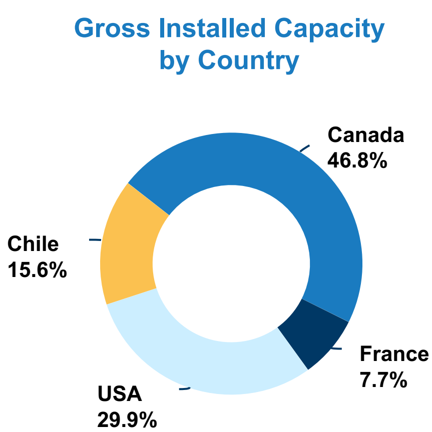
Innergex measures its performance using key performance indicators ("KPIs"). Innergex believes that these indicators are important, as they provide management and the reader with additional information about its production and cash-generating capabilities, its ability to pay dividends and fund its growth.

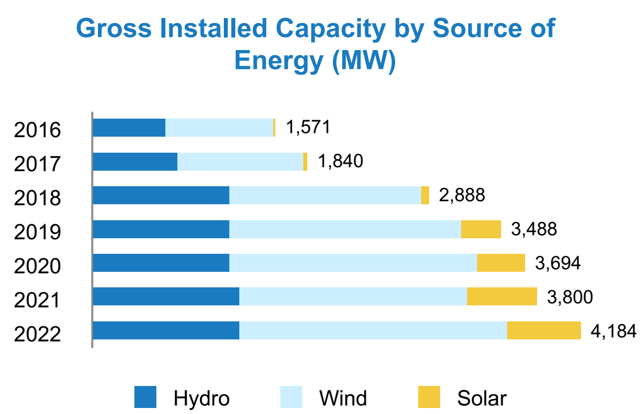
These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

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 August 3, 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 farms, 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 on 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 August 3, 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 9.3 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 13.7 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 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 August 3, 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	226	32	—	—
United States	8	1	714	330	662	330	—	—
Chile	3	—	332	—	332	—	—	—
Subtotal	35	3	2,278	368	1,934	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	3,484	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 six-month periods ended June 30, 2022, and reflects all material events up to August 3, 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 six-month periods ended June 30, 2022.

The unaudited condensed interim consolidated financial statements attached to this MD&A and the accompanying notes for the three-and six-month periods ended June 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 | Second Quarter 2022 – Growth Initiatives

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

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

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

The **Salvador Battery Storage project** with a 50 MW/250 MWh (5 hours) capacity was promoted to the construction phase with an expected Commercial Operation Date ("COD") in 2023.

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

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

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 | Updated 2022 Growth Targets

The Corporation makes targets using certain assumptions to provide readers with an indication of its business activities and operating performance. For 2022, targets were based on the commissioning of the Tonnerre battery storage project in the first quarter of 2022 and the Innavik hydro facility in the fourth quarter of 2022. The Tonnerre battery storage project reached COD in the third quarter of 2022 and the Corporation now expects the Innavik hydro facility to be in operation in 2023. It did not take into consideration potential acquisitions that could be achieved in 2022.

Since the Corporation made these assumptions at the beginning of the year, the targets were revised in August 2022 to take into consideration the acquisition of the San Andrés solar facility on January 28, 2022, and the acquisition of the Aela wind farms on June 9, 2022. The targets were also revised to take into consideration below-average water flows, wind regimes and solar irradiation at some facilities during the first six-month period of 2022. The Corporation did not revise any other assumptions from the initial 2022 Growth Targets presented in the 2021 Annual Report with the exception of a lower assumed Euro to Canadian dollar exchange rate.

The following table summarizes the revised targets for 2022:

	February 2022	August 2022
	Target	Revised Target
Production (GWh)[1]	≈ +18%	≈ +22%
Revenues	≈ +16%	≈ +25%
Operating, general, administrative and prospective projects expenses	≈ +18%	≈ +27%
Adjusted EBITDA[1]	≈ +15%	≈ +25%
Adjusted EBITDA Proportionate[1]	≈ +14%	≈ +21%
Free Cash Flow per Share[1]	≈ 0.73	≈ 0.75
Number of facilities in operation	82	84
Net installed capacity (MW)	3,156	3,484

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production is a key performance indicator for the Corporation that cannot be reconciled with an IFRS measure. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

These assumptions are based on information available to the Corporation and the list of assumptions is not exhaustive. These assumptions, although considered reasonable by the Corporation on August 3, 2022, may prove to be inaccurate. Important risks and uncertainties may cause actual results or performance to be materially different from the Corporation's expectations as set forth in this section. The risks and uncertainties are referred to in the "Risks and Uncertainties" section of the 2021 Annual Report.

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

1- HIGHLIGHTS | Second Quarter 2022 – Selected Information

	Three months ended June 30		Six months ended June 30			
	2022	2021	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized
OPERATING RESULTS						
Production (MWh)	2,855,891	2,396,027	5,160,494	4,181,975	—	4,181,975
Revenues	219,746	170,605	408,469	360,256	(54,967)	305,289
Operating, general, administrative and prospective projects expenses	66,874	47,920	125,071	94,452	—	94,452
Adjusted EBITDA[1]	152,872	122,685	283,398	265,804	(54,967)	210,837
Adjusted EBITDA Margin[1]	69.6 %	71.9 %	69.4 %	73.8 %	(4.7)%	69.1 %
Net (Loss) Earnings	(24,590)	50,199	(59,520)	(167,673)	64,219	(103,454)
Adjusted Net Loss[1]	(1,546)	18,658	(3,882)	(8,882)	—	(8,882)
PROPORTIONATE						
Production Proportionate (MWh)[1]	2,991,550	2,588,928	5,349,579	4,638,549	—	4,638,549
Revenues Proportionate[1]	251,457	198,400	467,571	460,135	(95,273)	364,862
Adjusted EBITDA Proportionate[1]	181,079	145,962	335,989	354,853	(95,273)	259,580
Adjusted EBITDA Proportionate Margin[1]	72.0 %	73.6 %	71.9 %	77.1 %	(6.0)%	71.1 %
COMMON SHARES						
Dividends declared on Common Shares	36,739	31,433	73,472	62,877	—	62,877
Dividends declared on Series A Preferred Shares	689	689	1,379	1,379	—	1,379
Dividends declared on Series C Preferred Shares	718	718	1,437	1,437	—	1,437
Weighted Average Number of Common Shares (in 000s)	203,558	174,172	200,123	174,141	—	174,141

	Trailing twelve months ended June 30			
	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized
CASH FLOW AND PAYOUT RATIO				
Cash Flow From Operating Activities[2]	308,384	252,213	(16,801)	235,412
Free Cash Flow[1,2]	148,988	76,702	15,789	92,491
Payout Ratio[1,2]	96 %	164 %	(28)%	136 %
Adjusted Payout Ratio[1,2]	82 %	111 %	— %	111 %

FINANCIAL POSITION As at	June 30, 2022	December 31, 2021
Total Assets	8,445,273	7,396,068
Total Liabilities	6,876,517	6,035,388
Equity Attributable to Owners	1,324,417	1,093,112
Non-Controlling Interests	244,339	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 six-month period ended June 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 | Second Quarter 2022 – Operating Performance

For the three-month period ended June 30, 2022, **Revenues** were up 29% to $219.7 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. The increase was partly offset by the lower production from the facilities in British Columbia due to cooler weather delaying the melting season ("freshet"). 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 higher production from the Quebec facilities. The increase was partly offset by lower revenues from lower production from the facilities in France combined with a lower exchange rate. The increase in revenues from the **solar** power generation segment was mostly due to the higher selling prices at the Phoebe facility, the San Andrés Acquisition completed on January 28, 2022, the commissioning of the Amazon Solar Farm Ohio - Hillcrest ("Hillcrest") facility on May 11, 2021 and the contribution of the Pampa Elvira facility following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021. This increase was partly offset by lower selling prices at the Salvador facility. Revenues Proportionate[1] were up 27% at $251.5 million compared with the same period last year.

For the three-month period ended June 30, 2022, **Operating, general, administrative and prospective projects expenses** were up 40% to $66.9 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 of the facilities in Chile in 2021. In the **wind** power generation segment, these expenses increased due to the commissioning of the Griffin Trail facility on July 26, 2021, and to the acquisition of Aela on June 9, 2022. 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 25% higher at $152.9 million for three-month period ended June 30, 2022, compared with the same period last year. The Adjusted EBITDA Proportionate[1] reached $181.1 million, a 24% increase compared with the same period last year.

Innergex recorded a net loss of $24.6 million ($0.13 net loss per share - basic and diluted) for the quarter ended June 30, 2022, compared with net earnings of $50.2 million ($0.23 net earnings per share - basic and diluted) for the corresponding period in 2021. This was mainly due to a $45.2 million decrease in recovery of income tax, mainly stemming from the reversal of deferred tax liabilities in 2021 related to the Flat Top and Shannon joint venture facilities, due to the projects' assets and liabilities being classified as disposal groups held for sale, a $19.9 million increase in depreciation and amortization and an $18.4 million increase in finance costs, mainly attributable to the Energía Llaima, Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissioning in 2021. The increase in net loss is also explained by an unfavourable change in the mark to market of financial instruments and in the power hedge settlements, due to higher merchant prices. These items were partly offset by a $9.7 million increase in other net income, mainly related to the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility, following its commissioning during the third quarter of 2021.

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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 | Second 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. This was partly offset by depreciation and amortization and from 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 June 30, 2022, is mainly due to the contribution from the acquisitions and the Hillcrest and Griffin Trail commissionings. For the trailing twelve months ended June 30, 2022, Free Cash Flow[1] was impacted by the above, and the February 2021 Texas Events, as the Phoebe solar facility's $33.9 million net payable related to the February 2021 Texas Events remained unpaid until July 19, 2021.

1- HIGHLIGHTS | Subsequent Events

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 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 it's intention to cancel the agreement. The project will sell its electricity on a merchant price basis. The cancellation will take effect on November 1, 2022.

On July 22, 2022, the Corporation 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. Being Innergex’s first stand-alone battery project, the commissioning of Tonnerre is a considerable achievement in term of technological knowledge earned for future development opportunities. The market for battery energy storage systems will continue to increase to bring more reliability to the grids as more renewable energy projects are being developed.

[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 August 3, 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, the geographic segments in which Innergex operates have been impacted by rising inflation pressure as a result of increased customer spending 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 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 absorbed by higher revenues.

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

Energy segment	Location	Three months ended June 30, 2022		Three months ended June 30, 2021		Three months Production % change	Six months ended June 30, 2022		Six months ended June 30, 2021		Six months Production % change
		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA	
HYDRO	Quebec	211,514	99 %	212,646	99 %	(1)%	341,181	101 %	354,787	105 %	(4)%
	Ontario	21,617	104 %	10,234	49 %	111 %	45,298	100 %	33,162	74 %	37 %
	British Columbia	684,025	84 %	826,565	102 %	(17)%	855,200	83 %	970,177	95 %	(12)%
	United States[3]	105,440	95 %	17,726	105 %	495 %	205,371	97 %	22,105	89 %	829 %
	Chile[4]	105,470	109 %	—	— %	— %	155,939	90 %	—	— %	— %
	Subtotal	**1,128,066**	**90 %**	**1,067,171**	**100 %**	**6 %**	**1,602,989**	**89 %**	**1,380,231**	**96 %**	**16 %**
WIND	Quebec	516,371	102 %	462,054	91 %	12 %	1,220,618	102 %	1,100,232	92 %	11 %
	France	129,957	82 %	153,682	97 %	(15)%	337,815	86 %	360,892	93 %	(6)%
	United States	649,218	96 %	412,465	92 %	57 %	1,300,176	98 %	863,265	97 %	51 %
	Chile[6]	57,906	97 %	—	— %	— %	57,906	97 %	—	— %	— %
	Subtotal	**1,353,452**	**97 %**	**1,028,201**	**92 %**	**32 %**	**2,916,515**	**98 %**	**2,324,389**	**94 %**	**25 %**
SOLAR	Ontario	12,860	108 %	14,295	120 %	(10)%	18,891	101 %	20,217	107 %	(7)%
	United States	307,237	85 %	253,523	80 %	21 %	490,638	84 %	375,819	80 %	31 %
	Chile[4,5]	54,276	81 %	32,837	96 %	65 %	131,461	86 %	81,319	94 %	62 %
	Subtotal	**374,373**	**85 %**	**300,655**	**83 %**	**25 %**	**640,990**	**84 %**	**477,355**	**83 %**	**34 %**
TOTAL PRODUCTION[1]		**2,855,891**	**92 %**	**2,396,027**	**94 %**	**19 %**	**5,160,494**	**93 %**	**4,181,975**	**93 %**	**23 %**
Innergex's share of production of joint venture and associates		135,659	86 %	192,901	94 %	(30)%	189,085	92 %	456,574	93 %	(59)%
PRODUCTION PROPORTIONATE[1,2]		**2,991,550**	**92 %**	**2,588,928**	**94 %**	**16 %**	**5,349,579**	**93 %**	**4,638,549**	**93 %**	**15 %**

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 June 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, the unfavourable impact of the intermittent curtailment required by the distribution network in Texas at 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, the Quebec facilities and at the Mountain Air facilities in Idaho. Excluding Phoebe's economic curtailment, production for the US solar segment would have reached 97% of LTA. Innergex's share of production of joint ventures and associates was 86% 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 six-month period ended June 30, 2022, was 93% of LTA. The result is mostly explained by lower production at the facilities in British Columbia due to cooler weather delaying the freshet and the unfavourable impact of the intermittent curtailment required by the distribution network in Texas at 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, the Quebec facilities and at the Mountain Air facilities in Idaho. Excluding Phoebe's economic curtailment, production for the US solar segment would have reached 98% of LTA. Innergex's share of production of joint ventures and associates was 86% 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	— [4]
Innavik (QC, Canada)	Hydro	50	7.5	54.7	40	2023
Salvador Battery Storage (Chile)	Storage	100	Note [5]	—	—	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. Project schedule under revision.
5. 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 is completing civil works including site grading, fencing and site access roads.
- PPA repricing discussions are presently taking place.
- Project schedule is under revision.

Innavik:

- Derivation structure concreting is scheduled to be completed in Q3 2022.
- Powerhouse superstructure and envelope is now completed and turbines/generators installation is scheduled to start in Q3 2022.
- Footing of the dam sheet piles started in Q2 2022 and the dam should be completed in Q4 2022.
- Spillway concrete work is scheduled 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 only in 2023.
- Discussion with the EPC Contractor on commercial close-out in progress.
- Project COD postponed to Q1 2023.

Salvador Battery Storage

- Mobilization and site preparation started on June 9, 2022.
- Switchgear procurement underway.
- COD expected in Q2 2023.

(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
San Andrés Battery Storage (Chile)	Storage	— [1]	—	2023
Frontera (Chile)	Hydro	109.0	— [2]	— [5]
Rucacura (Chile)	Hydro	3.0	— [2]	2025
Lazenay (France)	Wind	9.0	— [2]	2023
Auxy Bois Régnier (France)	Wind	29.4	20	2024
Boswell Springs (Wyoming, U.S.)	Wind	329.8	30 [3]	2024
Paeahu (Hawaii, U.S.)	Solar	15.0 [4]	25	— [5]
Kahana (Hawaii, U.S.)	Solar	20.0 [4]	25	— [5]
Barbers Point (Hawaii, U.S.)	Solar	15.0 [4]	25	— [5]
Palomino (Ohio, U.S.)	Solar	200	15	2025

1. Battery storage capacity of 35 MW/175 MWh (5 hours).
2. Power to be sold on the open market or through PPAs yet to be signed.
3. The project has been selected to PacifiCorp's 2020 All-Source Request for Proposal final shortlist. Therefore, the project is currently negotiating the terms of a busbar take-or-pay 30-year PPA with PacifiCorp.
4. 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.
5. Project schedule under revision.

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 for the following projects:

Frontera
- Construction contract and permitting are progressing slowly, awaiting decisions on financial items.
- Project schedule is under revision.

Rucacura
- Waiting for quotations on electromechanical components and civil works.
- COD expected in 2025.

Lazenay
- The technical and financial proposal (PTF) for a connection to the Public Power Distribution Network in Q2 2024 has been signed and the deposit has been paid.

Boswell Springs
- EPC contractor has been selected.
- Permitting is complete.
- The project is eligible to received 100% of the production tax credit (please refer to the "Tax Equity Investment" section of this MD&A)

Paeahu
- The project has been delayed by an unfavourable decision at the circuit court regarding the county special use permit due to local opposition. The project commenced a new proceeding with the Maui County Planning Commission on the required permit in April 2022. The mediation phase was conducted in May 2022. Unfortunately, the parties were not able to come to a mediated resolution. The project will undergo a contested case proceeding later in 2022, currently anticipate a late September court date.
- PPA was approved by the Hawaii Public Utilities Commission ("PUC") on October 5, 2020. The project received a favourable decision at the Hawaii Supreme Court on March 2, 2022 upholding the PUC approval of the PPA. The PPA offtaker confirmed the effective date of the PPA is July 1, 2022. Project plans to use the maximum 148 days extension allowed in the PPA to reach COD.

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

- On June 6, 2022, the US President issued an executive order exempting potential new tariffs imposed by the anti circumvention inquiry for 24 months. Depending on the revised schedule, the project may still be at risk.

Kahana
- The Overhead Line was approved by the Hawaii PUC on June 27, 2022.
- On June 6, 2022, the US President issued an executive order exempting potential new tariffs imposed by the anti circumvention inquiry for 24 months. Depending on the revised schedule, the project may still be at risk.

Barbers Point
- On June 6, 2022, the US President issued an executive order exempting potential new tariffs imposed by the anti circumvention inquiry for 24 months. Depending on the revised schedule, the project may still be at risk.

Palomino
- Executed term sheet to secure a supply of panels for the Project.
- On June 14, 2022, the Ohio Power Siting Board Staff Report of Investigation recommended the Certificate of Environmental Compatibility and Public Need for the Project be issued.

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 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	1,963	12	2,400	6	—	—	4,363	18
Subtotal	2,743	32	2,400	6	—	—	5,143	38
UNITED STATES								
Solar	698	8	150	1	520	2	1,368	11
Wind	—	—	400	1	—	—	400	1
Green hydrogen[2]	5	1	—	—	—	—	5	1
Subtotal	703	9	550	2	520	2	1,773	13
FRANCE								
Solar	—	—	—	—	85	1	85	1
Wind	49	3	72	4	149	8	270	15
Subtotal	49	3	72	4	234	9	355	16
CHILE								
Hydro	29	2	—	—	154	1	183	3
Solar	32	1	—	—	—	—	32	1
Wind	9	1	—	—	—	—	9	1
Subtotal	70	4	—	—	154	1	224	5
Total	3,565	48	3,022	12	908	12	7,495	72
Changes from Q1 2022	+47	—	+369	+2	+400	+1	+816	+3

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 Q1 2022, two new projects were added to the Mid Stage in Canada. In the United States, one project downgraded from the Mid Stage to the Early Stage and one project moved from the Mid Stage to the Advanced Stage. In France, one project moved from the Early Stage to the Mid Stage and a new one was added to the Mid Stage.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS

	Three months ended June 30				Six months ended June 30					
	2022	2021	Change		2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized[3]	Change	
Revenues	219,746	170,605	49,141	29 %	408,469	360,256	(54,967)	305,289	103,180	34 %
Operating expenses	50,546	30,163	20,383	68 %	90,584	61,156	—	61,156	29,428	48 %
General and administrative expenses	10,540	11,023	(483)	(4)%	24,679	20,773	—	20,773	3,906	19 %
Prospective projects expenses	5,788	6,734	(946)	(14)%	9,808	12,523	—	12,523	(2,715)	(22)%
Adjusted EBITDA[1]	152,872	122,685	30,187	25 %	283,398	265,804	(54,967)	210,837	72,561	34 %
Adjusted EBITDA margin[1]	69.6 %	71.9 %			69.4 %	73.8 %	(4.7)%	69.1 %		
Finance costs	77,159	58,719	18,440	31 %	143,560	118,319	—	118,319	25,241	21 %
Other net income	(18,983)	(9,325)	(9,658)	104 %	(39,112)	(21,229)	—	(21,229)	(17,883)	84 %
Depreciation and amortization	79,113	59,169	19,944	34 %	159,344	118,054	—	118,054	41,290	35 %
Impairment of long-term assets	—	6,314	(6,314)	(100)%	—	6,314	—	(6,314)	6,314	(100)%
Share of losses (earnings) of joint ventures and associates:[2]										
Share of losses (earnings), before impairment charges	(1,222)	(2,993)	1,771	(59)%	986	92,382	(64,197)	28,185	(27,199)	(97)%
Share of impairment charges	—	—	—	— %	—	112,609	—	112,609	(112,609)	(100)%
Change in fair value of financial instruments	40,041	4,458	35,583	798 %	80,556	92,167	(72,060)	20,107	60,449	301 %
Income tax expense (recovery)	1,354	(43,856)	45,210	(103)%	(2,416)	(85,139)	17,071	(68,068)	65,652	(96)%
Net (loss) earnings	(24,590)	50,199	(74,789)	(149)%	(59,520)	(167,673)	64,219	(103,454)	43,934	(42)%
(Net loss) earnings attributable to:										
Owners of the parent	(25,185)	41,102	(66,287)	(161)%	(59,587)	(173,059)	64,219	(108,840)	49,253	(45)%
Non-controlling interests	595	9,097	(8,502)	(93)%	67	5,386	—	5,386	(5,319)	(99)%
	(24,590)	50,199	(74,789)	(149)%	(59,520)	(167,673)	64,219	(103,454)	43,934	(42)%
Basic and diluted net (loss) earnings per share from continuing operations attributable to owners ($)	(0.13)	0.23			(0.31)	(1.01)	0.37	(0.64)		

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 June 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)

Hydroelectric Segment	Three months ended June 30			Six months ended June 30		
	2022	2021	Change	2022	2021	Change
Production (MWh)	1,128,066	1,067,171	6 %	1,602,989	1,380,231	16 %
LTA (MWh)	1,256,499	1,064,950	18 %	1,794,967	1,434,632	25 %
Revenues (in $M)	100,119	75,926	32 %	166,030	102,496	62 %
Operating, general and administrative expenses	23,742	12,899	84 %	43,023	24,979	72 %
Adjusted EBITDA (in $M)[1]	76,377	63,027	21 %	123,007	77,517	59 %
Adjusted EBITDA Margin[1]	76.3 %	83.0 %		74.1 %	75.6 %	
PROPORTIONATE[1]						
Production Proportionate (MWh)	1,243,834	1,234,012	1 %	1,733,403	1,585,164	9 %
Revenues Proportionate (in $M)	110,506	91,156	21 %	179,647	122,065	47 %
Adjusted EBITDA Proportionate (in $M)	84,192	74,660	13 %	131,962	90,657	46 %
Adjusted EBITDA Margin Proportionate	76.2 %	81.9 %		73.5 %	74.3 %	

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 June 30, 2022, the increase of 32% 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 partly offset by lower production at the facilities in British Columbia due to cooler weather delaying the freshet. The increase of 84% in Operating, general and administrative expenses is explained by higher maintenance costs at some facilities in British Columbia, higher expenses following the acquisition of Curtis Palmer 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 21% to $76.4 million. The Adjusted EBITDA Margin[1] was down from 83.0% to 76.3%, mainly explained by lower contributions from facilities in British Columbia due to lower revenues and higher operating expenses, partly offset by the Curtis Palmer Acquisition, for which margins are higher.

For the three-month period ended June 30, 2022, the increase in Revenues Proportionate[1] in the hydroelectric segment was partly offset by the joint ventures' and associates' Revenues, which decreased compared to 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 and due to the lower revenues from lower production at the facilities in British Columbia. 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 13% to $84.2 million.

For the six-month period ended June 30, 2022, the increase of 62% 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. The increase is partly offset by lower revenues from lower production at the facilities in British Columbia due to cooler weather delaying the freshet. The increase of 72% in Operating, general and administrative expenses is explained by higher maintenance costs at some facilities in British Columbia following the flooding that occured at the end of 2021, higher expenses following the acquisition of Curtis Palmer 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 59% to $123.0 million. The Adjusted EBITDA Margin[1] was down from 75.6% to 74.1%, mainly explained by lower contribution from facilities in British Columbia due to lower revenues and 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 six-month period ended June 30, 2022, the increase in Revenues Proportionate[1] in the hydroelectric segment 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 46% to $132.0 million.

	Three months ended June 30			Six months ended June 30				
Wind Segment	2022	2021	Change	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	1,353,452	1,028,201	32 %	2,916,515	2,324,389	—	2,324,389	25 %
LTA (MWh)	1,401,788	1,115,257	26 %	2,980,770	2,479,946	—	2,479,946	20 %
Revenues (in $M)	85,638	72,815	18 %	191,535	188,828	(16,801)	172,027	11 %
Operating, general and administrative expenses	22,220	15,179	46 %	38,641	31,569	—	31,569	22 %
Adjusted EBITDA (in $M)[1]	63,418	57,636	10 %	152,894	157,259	(16,801)	140,458	9 %
Adjusted EBITDA Margin[1]	74.1 %	79.2 %		79.8 %	83.3 %	(4.3)%	81.6 %	
PROPORTIONATE[1]								
Production Proportionate (MWh)	1,373,343	1,051,617	31 %	2,975,186	2,570,490	—	2,570,490	16 %
Revenues Proportionate (in $M)	106,962	84,999	26 %	237,020	268,253	(57,107)	211,146	12 %
Adjusted EBITDA Proportionate (in $M)	83,810	69,024	21 %	196,530	232,614	(57,107)	175,507	12 %
Adjusted EBITDA Margin Proportionate	78.4 %	81.2 %		82.9 %	86.7 %	(6.2)%	83.1 %	

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 six-month period ended June 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 June 30, 2022, Revenues increased by 18% 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, the higher production from the facilities in Quebec and to the acquisition of the Aela wind farms, completed on June 9, 2022. The increase was partly offset by lower revenues from lower production at the facilities in France combined with a lower exchange rate. The increase of 46% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Griffin Trail facility and the acquisition of the Aela wind farms. As a result, the Adjusted EBITDA[1] increased by 10% to $63.4 million, compared with the same period last year. The Adjusted EBITDA Margin[1] was down from 79.2% to 74.1%, mainly explained by the commissioning of Griffin Trail, for which margins are variable.

For the three-month period ended June 30, 2022, the increase in Revenues Proportionate[1] was explained by the consolidated facilities and the increase of Production Tax Credits ("PTCs") generated by the wind farms mostly due to the Griffin Trail facility following its commissioning on July 26, 2021. 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 21% to $83.8 million.

For the six-month period ended June 30, 2022, Revenues increased by 11% 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 higher production from the facilities in Quebec and to the acquisition of the Aela wind farms, completed on June 9, 2022. The increase was partly offset by lower revenues from lower production at the facilities in France combined with a lower exchange rate and by mechanical issues and lower selling prices at the Foard City facility. The increase of 22% in Operating, general and administrative expenses is due to the commissioning of the Griffin Trail facility and the acquisition of the Aela wind farms This increase was partly offset by lower variable expenses following lower revenues at the Foard City facility and lower expenses in France due to a lower exchange rate. As a result, the Adjusted EBITDA[1] increased by 9% to $152.9 million, compared with the same period last year, for which the Adjusted EBITDA[1] was normalized to exclude the

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

February 2021 Texas Events. The Adjusted EBITDA Margin[1] was down from 81.6% to 79.8%, on a normalized basis, explained by lower revenues in France and by the Griffin Trail commissioning, for which margins are variable, partly offset by higher margins in Quebec.

For the six-month period ended June 30, 2022, the increase 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 Griffin Trail facility following its commissioning 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 12% to $196.5 million, on a normalized basis.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Solar Segment

	Three months ended June 30			Six months ended June 30				
Solar Segment	2022	2021	Change	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	374,373	300,655	25 %	640,990	477,355	—	477,355	34 %
LTA (MWh)	442,101	362,854	22 %	758,816	575,373	—	575,373	32 %
Revenues (in $M)	33,989	21,864	55 %	50,904	68,932	(38,166)	30,766	65 %
Operating, general and administrative expenses	5,501	2,421	127 %	11,106	5,414	—	2,421	359 %
Adjusted EBITDA (In $M)[1]	28,488	19,443	47 %	39,798	63,518	(38,166)	25,352	57 %
Adjusted EBITDA Margin[1]	83.8 %	88.9 %		78.2 %	92.1 %	(11.2)%	82.4 %	
PROPORTIONATE[1]								
Production Proportionate (MWh)	374,373	303,299	23 %	640,990	482,895	—	482,895	33 %
Revenues Proportionate (In $M)	33,989	22,245	53 %	50,904	69,817	(38,166)	31,651	61 %
Adjusted EBITDA Proportionate (In $M)	28,488	19,699	45 %	39,798	64,072	(38,166)	25,906	54 %
Adjusted EBITDA Margin Proportionate	83.8 %	88.6 %		78.2 %	91.8 %	(11.5)%	81.8 %	

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 three months ended March 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

For the three-month period ended June 30, 2022, Revenues increased 55% in the solar power generation segment compared with the same period last year, due mainly to the higher selling prices at the Phoebe facility, the San Andrés Acquisition completed on January 28, 2022, the commissioning of the Hillcrest facility in 2021 and to the contribution of the Pampa Elvira facility following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021. This increase was partly offset by lower average selling prices at the Salvador facility. The increase of 127% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Hillcrest facility in 2021 and the acquisition of the San Andrés and Pampa Elvira facilities. As a result, the Adjusted EBITDA[1] increased by 47% to $28.5 million, compared with the same period last year. The Adjusted EBITDA Margin[1] was down from 88.9% to 83.8%, mainly explained by the Hillcrest commissioning, for which margins are lower and partly offset by higher revenues at the Phoebe facility.

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

For the six-month period ended June 30, 2022, Revenues increased 65% in the solar power generation segment compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events. The increase is mainly attributable to the higher selling prices at the Phoebe facility, the commissioning of the Hillcrest facility in 2021, 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 359% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Hillcrest facility and the acquisition of the San Andrés and Pampa Elvira facilities. As a result, the Adjusted EBITDA[1] increased by 57% to $39.8 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 82.4% to 78.2%, 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 June 30, 2022, on a consolidated basis, the Adjusted EBITDA[1] was up 25% from $122.7 million to $152.9 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 down from 71.9% to 69.6%. This decrease is mainly explained by the lower revenues from the hydro facilities in British Columbia, lower revenues from the wind facilities in France and by certain facilities recently commissioned and acquired, for which margins are lower.

For the three-month period ended on June 30, 2022, the Adjusted EBITDA Proportionate Margin[1] was down from 73.6% to 72.0%. This decrease is explained by lower Adjusted EBITDA margin[1,2] partly offset by higher PTCs earned from the Griffin Trail facility following its commissioning on July 26, 2021.

For the six-month period ended June 30, 2022, on a consolidated basis, the Adjusted EBITDA[1] was up 34% from $210.8 million to $283.4 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 69.1% to 69.4%. 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 lower revenues from the hydro facilities in British Columbia and certain facilities recently commissioned and acquired, for which margins are lower.

For the six-month period ended June 30, 2022, the Adjusted EBITDA Proportionate Margin[1], on a normalized basis to exclude the February 2021 Texas Events, was up from 71.1% to 71.9%. This increase is explained by higher PTCs earned from the Griffin Trail facility following its commissioning on July 26, 2021, partly offset by lower Adjusted EBITDA margin[1,2].

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 loss of $24.6 million ($0.13 net loss per share - basic and diluted) for the three-month period ended June 30, 2022, compared with a net earnings of $50.2 million ($0.23 net earning 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 $74.8 million increase in net loss mainly stems from:

- a $45.2 million decrease in recovery of income tax, mainly stemming from the reversal of deferred tax liabilities in 2021 related to the Flat Top and Shannon joint venture facilities, due to the projects' assets and liabilities being classified as disposal groups held for sale;
- an unfavourable $25.6 million unrealized change in the fair value of financial instruments, mainly related to the increase in merchant power curves for the Phoebe power hedge and an unfavourable change in foreign exchange forward curves, and partly offset by a favourable change in interest rate curves, compared with the same period in 2021;
- a $19.9 million increase in depreciation and amortization, mainly attributable to the Energía Llaima, Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissioning in 2021;
- an $18.4 million increase in finance costs mainly related to the Griffin Trail and Hillcrest facilities, the Energía Llaima and Aela acquisitions, and an increase in inflation compensation interests on the Harrison Hydro real return bonds; and
- an unfavourable $10.0 million realized change in the fair value of financial instruments, mainly related to higher merchant prices in 2022 affecting the Phoebe power hedge.

These items were partly offset by:
- a $9.7 million increase in other net income, mainly related to the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility, following its commissioning during the third quarter of 2021.

Net loss of $59.5 million ($0.31 net loss per share - basic and diluted) for the six-month period ended June 30, 2022, compared with a net loss of $167.7 million ($1.01 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 $108.2 million decrease in net loss mainly stems from:

- a $204.0 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;
- a favourable $61.4 million realized change in the fair value of financial instruments, mainly stemming from the net unfavourable impact of the February 2021 Texas Events in 2021, partly offset by higher merchant prices in 2022 affecting the Phoebe power hedge; and
- a $17.9 million increase in other net income, mainly related to the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility, following its commissioning during the third quarter of 2021.

These items were partly offset by:
- an $82.7 million decrease in recovery of income tax, mainly related to the impacts of the February 2021 Texas Events, the Flat Top and Shannon impairment charges in 2021, and the reversal of deferred tax liabilities related to the Flat Top and Shannon joint venture facilities, due to the projects' assets and liabilities being classified as disposal groups held for sale;
- an unfavourable $49.8 million unrealized change in the fair value of financial instruments, mainly related to the increase in merchant power curves for the Phoebe power hedge and an unfavourable movement in the unrealized portion of the change in fair value on the Phoebe basis hedge following its maturity in 2021, partly offset by a favourable change in interest rate curves, compared with the same period in 2021;
- a $41.3 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 $25.2 million increase in finance costs mainly related to the Griffin Trail and Hillcrest facilities commissioned in 2021, the Energía Llaima and Aela acquisitions, and an increase in inflation compensation interests on the Harrison Hydro real return bonds.

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 June 30		Six months ended June 30	
	2022	2021	2022	2021
Revenues	219,746	170,605	408,469	305,289
Expenses:				
Operating expenses	50,546	30,163	90,584	61,156
General and administrative expenses	10,540	11,023	24,679	20,773
Prospective project expenses	5,788	6,734	9,808	12,523
Adjusted EBITDA[1]	152,872	122,685	283,398	210,837
Finance costs	77,159	58,719	143,560	118,319
Other net income	(18,983)	(8,892)	(38,625)	(20,481)
Depreciation and amortization	79,113	59,169	159,344	118,054
Share of (earnings) losses of joint ventures and associates	(753)	(3,465)	2,353	1,919
Realized loss on power hedges	12,329	3,745	12,059	91
Income tax expense (recovery)	5,553	(5,249)	8,589	1,817
Adjusted Net (Loss) Earnings[1]	(1,546)	18,658	(3,882)	(8,882)

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 $1.5 million for the three-month period ended June 30, 2022, compared with an Adjusted Net Earnings[1] of $18.7 million for the corresponding period in 2021.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, the $20.2 million increase in Adjusted Net Loss[1] mainly stems from:

- a $19.9 million increase in depreciation and amortization, mainly attributable to the Energía Llaima, Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissioning in 2021;
- an $18.4 million increase in finance costs mainly related to the Griffin Trail and Hillcrest facilities, the Energía Llaima and Aela acquisitions, and an increase in inflation compensation interests on the Harrison Hydro real return bonds;
- a $10.8 million increase in income tax expense, mainly due to amounts attributable to Tax Equity Investors; and
- an unfavourable $8.6 million realized change in the fair value of financial instruments, mainly related to higher merchant prices in 2022 affecting the Phoebe power hedge.

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

These items were partly offset by:
- a $10.1 million increase in other net income, mainly related to the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility, following its commissioning during the third quarter of 2021.

Adjusted Net Loss[1] of $3.9 million for the six-month period ended June 30, 2022, compared with an Adjusted Net Loss[1] of $8.9 million for the corresponding period in 2021.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously discussed, the $5.0 million decrease in Adjusted Net Loss[1] mainly stems from:
- an $18.1 million increase in other net income, mainly related to the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility, following its commissioning during the third quarter of 2021.

These items were partly offset by:
- a $41.3 million increase in depreciation and amortization**,** mainly attributable to the Energía Llaima, Aela and Curtis Palmer acquisitions, and the Griffin Trail and Hillcrest commissioning in 2021;
- a $25.2 million increase in finance costs mainly related to the Griffin Trail and Hillcrest facilities, and the Energía Llaima and Aela acquisitions;
- an unfavourable $12.0 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 $6.8 million increase in income tax, mainly due to amounts attributable to Tax Equity Investors.

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

Attribution of earnings of $0.6 million to non-controlling interests for the three-month period ended June 30, 2022, compared with an attribution of earnings of $9.1 million for the corresponding period in 2021.

The $8.5 million decrease in earnings attributed to non-controlling interests for the three-month period ended June 30, 2022, is mainly due to:
- a higher allocation of losses to the non-controlling interests of Harrison Hydro, largely due to an increase in the inflation compensation interest on the real return bonds, compared with the same period last year, and
- an unfavourable unrealized change in the fair value of derivative financial instruments in Innergex Europe; as well as a decrease in revenues due to lower production from the French facilities.

These items were partly offset by:
- the earnings allocated to the non-controlling interests in Innergex HQI USA following the Curtis Palmer Acquisition in the fourth quarter of 2021.

Attribution of earnings of $0.1 million to non-controlling interests for the six-month period ended June 30, 2022, compared with earnings of $5.4 million for the corresponding period in 2021.

The $5.3 million decrease in earnings attributed to non-controlling interests for the six-month period ended June 30, 2022, is mainly due to:
- a higher allocation of losses to the non-controlling interests of Harrison Hydro, largely due to an increase in the inflation compensation interest on the real return bonds, compared with the same period last year; and
- an unfavourable unrealized change in the fair value of derivative financial instruments in Innergex Europe; as well as a decrease in revenues due to lower production from the French facilities.

These items were partly offset by:
- the earnings allocated to the non-controlling interests in Innergex HQI USA following the Curtis Palmer Acquisition in the fourth quarter of 2021; 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 June 30, 2022	As at December 31, 2021
Equity[1]		
Common shares[2]	3,530,993	3,580,388
Preferred shares[3]	100,680	109,080
Non-controlling interests	244,339	267,568
	3,876,012	3,957,036
Long-term loans and borrowings[1]		
Corporate revolving credit facility	748,211	398,758
Other corporate debt	305,000	295,000
Project-level debt	3,953,680	3,562,380
Tax Equity financing	441,136	455,967
Convertible debentures	281,449	280,258
Deferred financing costs	(67,471)	(67,928)
	5,662,005	4,924,435
	9,538,017	8,881,471

1.Common and preferred shares are presented at their fair value as at June 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 June 30, 2022, and December 31, 2021, multiplied by the prevailing share price of $17.30 (2021 - $18.60) at the close of markets.
3.Consists of the number of preferred shares outstanding as at June 30, 2022, and December 31, 2021, multiplied by the prevailing share price of $15.80 and $23.48 (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 a draw on the revolving credit facility and the acquisition of project debt, both stemming from the Aela Acquisition.

The effective all-in interest rate on the Corporation's long-term loans and borrowings was 4.75% as at June 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 June 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

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. As at June 30, 2022, the credit amounts to US$26/MWh generated, and subject to annual CPI inflation adjustment. Projects that commenced construction[1] before 2017 are eligible for 100% of the credit, decreasing annually by tranches of 20%, to 60% of the credit for projects that commenced construction[1] between January 1 and December 31, 2021. There is no PTC credit for projects that commence construction[1] on or after January 1, 2022. Certain of Innergex's forthcoming wind projects qualify for the credit under safe harbour provisions[1]. Both Foard City and Griffin Trail were eligible for the full 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	43.7	4.6	99.00 %	5.00 %
Griffin Trail[1,2]	2021	2031	210.6	27.8	4.9	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 1.2886. 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 1.2886. 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. Projects that commenced construction[1] before 2021 are eligible for 30% ITC. This credit decreases to 26% for facilities that commence construction[1] in 2021 and 2022, 22% in 2023 and 10% thereafter.

	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 ($116.5 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.

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[1]Specifically, to be eligible for the credit, the regulations stipulate that, for construction to be deemed to have commenced, a project must have either invested 5% of the total cost of the project or started "physical work of a significant nature," and prove that work is continuing on the project.

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

4- CAPITAL AND LIQUIDITY | Financial Position

As at	June 30, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	224,921	166,266
Restricted cash	50,969	61,659
Investment tax credits recoverable	1,220	1,200
Other current assets	224,336	159,552
Total current assets	501,446	388,677
Non-current assets		
Property, plant and equipment	6,122,552	5,513,392
Intangible assets	1,197,713	1,043,994
Investments in joint ventures and associates	132,304	133,398
Goodwill	59,017	60,858
Other non-current assets	432,241	255,749
Total non-current assets	7,943,827	7,007,391
Total assets	8,445,273	7,396,068
LIABILITIES		
Current liabilities	648,210	733,527
Non-current liabilities		
Long-term loans and borrowings	5,298,526	4,411,239
Other non-current liabilities	929,781	890,622
Total non-current liabilities	6,228,307	5,301,861
Total liabilities	6,876,517	6,035,388
SHAREHOLDERS' EQUITY		
Equity attributable to owners	1,324,417	1,093,112
Non-controlling interests	244,339	267,568
Total shareholders' equity	1,568,756	1,360,680
	8,445,273	7,396,068

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

Working Capital Items

As at June 30, 2022, working capital[1] was negative at $146.8 million, from negative $344.9 million in 2021, mainly explained by:

- Current assets amounted to $501.4 million as at June 30, 2022, an increase of $112.8 million compared with December 31, 2021, mainly due to a $58.7 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. The increase in accounts receivable is attributable mainly to the Aela Acquisition, and the higher revenues from higher production from the hydroelectric facilities in the spring. The increase in prepaid and other is mainly due to timing and to the facilities acquired in Chile.

- Current liabilities amounted to $648.2 million as at June 30, 2022, a decrease of $85.3 million compared with December 31, 2021, mainly due to a $148.9 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 milion subordinated unsecured term loan as current, due to the upcoming maturity on February 6, 2023.

- Derivative financial instruments also contributed unfavourably 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 June 30, 2022, the Corporation had $950.0 million in revolving term credit facility and had drawn $748.2 million as cash advances, while $52.8 million had been used to issue letters of credit, leaving $149.0 million available. In addition, a portion of the revolving term credit facility was used toward the Aela Acquisition pending refinancing of the non-recourse debt of Innergex's Chilean projects.

Non-Current Assets

Non-current assets amounted to $7,943.8 million as at June 30, 2022, an increase of $936.4 million compared with December 31, 2021. The increase is mainly due to an aggregate addition of $907.6 million to property, plant and equipment and intangible assets as part of the Alea 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 $51.8 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 $159.3 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 $6,228.3 million as at June 30, 2022, an increase of $926.4 million compared with December 31, 2021. The increase is mainly due to a $887.3 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 from net draws on the revolving term credit facility, used towards the Aela 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).

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. In addition, the decrease is also explained by a change in the derivative financial instruments' fair values (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information).

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

Shareholders' Equity

As at June 30, 2022, Shareholders' equity increased by $208.1 million compared with December 31, 2021, mainly attributable to the shares issued as part of to 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 $120.8 million, partly offset by the dividends declared on common and preferred shares totalling $76.3 million, and $33.1 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 $102.3 million as at June 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 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 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.

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.

On July 26, 2019, the Environmental Appeal Board of British Columbia rendered a decision granting the appeal and ordering the Comptroller of Water Rights to reimburse to each of the Limited Partnerships its proportionate share of the adjusted water rental amounts of $3.2 million overcharged to Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012. On November 22, 2019, the Environmental Appeal Board of British Columbia rendered another decision confirming that the sum will accrue interest starting June 28, 2017, until the date it is refunded. On January 20, 2020, the Comptroller of Water Rights filed with the Supreme Court of British Columbia a petition for judicial review of the Environmental Appeal Board’s order to return the amount in water rental fees to Harrison Hydro L.P. and its subsidiaries, with interest. The Limited Partnerships have filed their response to petition on April 14, 2020. The hearing took place in Victoria in the last week of September 2020. A decision was rendered on February 9, 2021, by the Supreme Court of British Columbia, which concluded that the Environmental Appeal Board's decision was reasonable, and dismissed the Comptroller of Water Rights' petition accordingly. The Comptroller of Water Rights subsequently appealed the decision of the Supreme Court of British Columbia; the appeal was unanimously dismissed by the British Columbia Court of Appeal on January 7, 2022. The Corporation recognized the amount of $3.2 million in the consolidated statements of earnings (loss) during the year ended December 31, 2019. A total amount of $3.4 million, including interest, was received by the Corporation during the first quarter of 2022.

Off-Balance-Sheet Arrangements

As at June 30, 2022, the Corporation had issued letters of credit totalling $226.6 million, including $52.8 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 $107.4 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, 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 June 30		Six months ended June 30			
	2022	2021	2022	2021	February 2021 Texas Events (9 days)	2021 Normalized [1]
OPERATING ACTIVITIES						
Cash flows from operating activities	67,628	49,639	152,486	109,609	(16,801)	92,808
FINANCING ACTIVITIES						
Cash flows from financing activities	345,836	(3,684)	349,754	41,501	—	41,501
INVESTING ACTIVITIES						
Cash flows used in investing activities	(394,417)	(72,666)	(444,687)	(154,550)	—	(154,550)
Effects of exchange rate changes on cash and cash equivalents	4,337	(1,034)	1,102	(4,380)	—	(4,380)
Net change in cash and cash equivalents	23,384	(27,745)	58,655	(7,820)	(16,801)	(24,621)
Cash and cash equivalents, beginning of period	201,537	181,390	166,266	161,465	—	161,465
Cash and cash equivalents, end of period	224,921	153,645	224,921	153,645	(16,801)	136,844

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 June 30, 2022, cash flows from operating activities totalled $67.6 million, compared with $49.6 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, and the Hillcrest and Griffin Trail commissionings. These items were partly offset by the distribution received from Energía Llaima in the second quarter of 2021.

For the six-month period ended June 30, 2022, cash flows from operating activities totalled $152.5 million, compared with $109.6 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, and the Hillcrest and Griffin Trail commissioning, and the BC Hydro Curtailment Payment. These items were partly offset by the distribution received from Energía Llaima in the second quarter of 2021, and the February 2021 Texas Events, which contributed to a $16.8 million increase in cash flows from operating activities in the comparative period, as the Phoebe solar facility's $33.9 million net payable related to the February 2021 Texas Events remained unpaid until July 19, 2021.

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

Cash Flows from Financing Activities

For the three-month period ended June 30, 2022, cash flows from financing activities totalled $345.8 million, compared with an outflow of $3.7 million in the same period last year. The increase stems mainly from the net $413.7 million increase in long-term loans and borrowings in 2022, mainly explained by the Aela Acquisition and the additions to property, plant and equipment. This compares with net draws of $41.5 million in 2021, mainly related to the construction of the Griffin Trail and Hillcrest facilities. The increase in cash flows from financing activities was partly offset by the distributions made to the non-controlling interests of Curtis Palmer acquired in late-2021.

For the six-month period ended June 30, 2022, cash flows from financing activities totalled $349.8 million, compared with $41.5 million in the same period last year. The increase stems mainly from the net $266.2 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 net increase of $125.6 million in 2021, mainly related to the construction of the Griffin Trail and Hillcrest facilities. The increase also stems from issuance of common shares as part of the public offering and the concurrent private placement to Hydro-Québec in February 2022 for a total amount of $202.2 million, used toward the Aela Acquisiton. The increase in cash flows from financing activities was partly offset by the distributions made to the non-controlling interests of Curtis Palmer acquired in late-2021.

Cash Flows Used in Investing Activities

For the three-month period ended June 30, 2022, cash flows used in investing activities totalled $394.4 million, compared with $72.7 million in the same period last year. The increase is mainly due to the consideration paid toward the Aela Acquisition, partly offset by the additions to property, plant and equipment made toward the Griffin Trail and Hillcrest facilities in 2021.

For the six-month period ended June 30, 2022, cash flows used in investing activities totalled $444.7 million, compared with $154.6 million in the same period last year. The increase is mainly due to the consideration paid toward the San Andrés and Aela acquisitions, partly offset by the additions to property, plant and equipment made toward 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 June 30			
	2022	2021	February 2021 Texas Events (9 days)[4]	2021 Normalized[4]
Cash flows from operating activities[5]	308,384	252,213	(16,801)	235,412
Add (Subtract) the following items:				
Changes in non-cash operating working capital items	45,659	596	33,894	34,490
Maintenance capital expenditures, net of proceeds from disposals	(9,095)	(4,921)	—	(4,921)
Scheduled debt principal payments	(161,411)	(155,540)	—	(155,540)
Free Cash Flow attributed to non-controlling interests[2]	(35,900)	(18,506)	—	(18,506)
Dividends declared on Preferred shares	(5,632)	(5,787)	—	(5,787)
Add (subtract) the following specific items[3]:				
Realized loss on contingent considerations	—	3,568	—	3,568
Realized (gain) loss on termination of interest rate swaps	(377)	2,885	—	2,885
Transaction costs related to realized acquisitions	9,660	1,696	—	1,696
Realized (gain) loss on the Phoebe basis hedge	(2,300)	498	(1,304)	(806)
Free Cash Flow[4]	148,988	76,702	15,789	92,491
Dividends declared on common shares	142,824	125,711	—	125,711
Payout Ratio[4]	96 %	164 %	(28)%	136 %
Adjust for the following items:				
Prospective projects expenses	24,652			20,830
Adjusted Free Cash Flow	173,640			113,321
Adjusted Payout Ratio	82 %			111 %

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. 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.
4. For the trailing twelve months ended June 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.
5. Cash flows from operating activities for the trailing twelve months ended June 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 June 30, 2022, the Corporation generated Free Cash Flow[1] of $149.0 million, compared with $76.7 million for the corresponding period last year (Normalized Free Cash Flow[1,2] of $92.5 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 $56.5 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, the Hillcrest and Griffin Trail commissioning; 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 project loan;
- 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 June 30, 2022, the dividends on common shares declared by the Corporation amounted to 96% of Free Cash Flow[1], compared with 164% 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 136% of Normalized Free Cash Flow[1,2].

[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		
	August 2, 2022	June 30, 2022	December 31, 2021
Number of common shares	204,116,917	204,103,658	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	316,922	316,922	265,570

As at the closing of the market on August 2, 2022, and since June 30, 2022, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 13,259 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at June 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 44,690 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 proceed with a normal course issuer bid on its common and 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.

(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 June 30				Six months ended June 30			
	2022		2021		2022		2021	
	($/share)	Total	($/share)	Total	($/share)	Total	($/share)	Total
Dividends declared on common shares[1]	0.180	36,739	0.180	31,433	0.3600	73,472	0.3600	62,877
Dividends declared on Series A Preferred Shares	0.2028	689	0.2028	689	0.4055	1,379	0.4055	1,379
Dividends declared on Series C Preferred Shares	0.3594	718	0.3594	718	0.7188	1,437	0.7188	1,437

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 October 17, 2022:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
August 3, 2022	September 30, 2022	October 17, 2022	$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 June 30, 2022				Three months ended June 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	219,746	12,944	18,767	251,457	170,605	18,302	9,493	198,400
Net loss (earnings)	(24,590)	—	—	(24,590)	50,199	—	—	50,199
Income tax expense (recovery)	1,354	—	—	1,354	(43,856)	(804)	—	(44,660)
Finance costs	77,159	4,476	—	81,635	58,719	5,210	—	63,929
Depreciation and amortization	79,113	4,222	—	83,335	59,169	5,610	—	64,779
Impairment of long-term assets	—	—	—	—	6,314	—	—	6,314
EBITDA	133,036	8,698	—	141,734	130,545	10,016	—	140,561
Other net income (expense), before PTCs	(216)	(14)	—	(230)	168	2	—	170
Production tax credits ("PTCs")	(18,767)	—	18,767	—	(9,493)	—	9,493	—
Share of losses of joint ventures and associates	(1,222)	1,222	—	—	(2,993)	2,993	—	—
Change in fair value of financial instruments	40,041	(466)	—	39,575	4,458	773	—	5,231
Adjusted EBITDA	152,872	9,440	18,767	181,079	122,685	13,784	9,493	145,962
Adjusted EBITDA Margin	69.6 %	72.9 %		72.0 %	71.9 %	75.3 %		73.6 %

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

	Six months ended June 30, 2022				Six months ended June 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	408,469	21,288	37,814	467,571	360,256	72,963	26,916	460,135
Net loss	(59,520)	—	—	(59,520)	(167,673)	—	—	(167,673)
Income tax recovery	(2,416)	—	—	(2,416)	(85,139)	(31)	—	(85,170)
Finance costs	143,560	8,900	—	152,460	118,319	14,305	—	132,624
Depreciation and amortization	159,344	8,418	—	167,762	118,054	14,565	—	132,619
Impairment of long-term assets	—	—	—	—	6,314	112,609	—	118,923
EBITDA	240,968	17,318	—	258,286	(10,125)	141,448	—	131,323
Other net income, before PTCs	(1,298)	(189)	—	(1,487)	(347)	1,870	—	1,523
Production tax credits ("PTCs")	(37,814)	—	37,814	—	(20,882)	(6,034)	26,916	—
Share of losses of joint ventures and associates	986	(986)	—	—	204,991	(204,991)	—	—
Change in fair value of financial instruments	80,556	(1,366)	—	79,190	92,167	129,840	—	222,007
Adjusted EBITDA	283,398	14,777	37,814	335,989	265,804	62,133	26,916	354,853
Adjusted EBITDA Margin	69.4 %	69.4 %		71.9 %	73.8 %	85.2 %		77.1 %

(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 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 June 30		Six months ended June 30	
	2022	2021	2022	2021
Net (loss) earnings	(24,590)	50,199	(59,520)	(167,673)
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	(345)	344	(1,005)	20,781
Unrealized portion of the change in fair value of financial instruments	27,712	2,158	68,497	18,681
Impairment of long-term assets	—	6,314	—	6,314
Realized loss on termination of interest rate swaps	—	—	—	2,885
Realized gain on the Phoebe basis hedge	—	(1,445)	—	(246)
Realized gain on foreign exchange forward contracts	—	(433)	(487)	(748)
Income tax recovery related to above items	(4,323)	(38,479)	(11,367)	(81,471)
Adjusted Net (Loss) Earnings	(1,546)	18,658	(3,882)	(8,882)

(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 June 30						Six months ended June 30					
	2022			2021			2022			2021		
	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS
Revenues	219,746	—	219,746	170,605	—	170,605	408,469	—	408,469	360,256	(54,967)	305,289
Operating expenses	50,546	—	50,546	30,163	—	30,163	90,584	—	90,584	61,156	—	61,156
General and administrative expenses	10,540	—	10,540	11,023	—	11,023	24,679	—	24,679	20,773	—	20,773
Prospective projects expenses	5,788	—	5,788	6,734	—	6,734	9,808	—	9,808	12,523	—	12,523
Adjusted EBITDA	152,872	—	152,872	122,685	—	122,685	283,398	—	283,398	265,804	(54,967)	210,837
Finance costs	77,159	—	77,159	58,719	—	58,719	143,560	—	143,560	118,319	—	118,319
Other net income	(18,983)	—	(18,983)	(9,325)	433	(8,892)	(39,112)	487	(38,625)	(21,229)	748	(20,481)
Depreciation and amortization	79,113	—	79,113	59,169	—	59,169	159,344	—	159,344	118,054	—	118,054
Impairment of long-term assets	—	—	—	6,314	(6,314)	—	—	—	—	6,314	(6,314)	—
Share of (earnings) losses of joint ventures and associates	(1,222)	469	(753)	(2,993)	(472)	(3,465)	986	1,367	2,353	204,991	(203,072)	1,919
Change in fair value of financial instruments	40,041	(27,712)	12,329	4,458	(713)	3,745	80,556	(68,497)	12,059	92,167	(92,076)	91
Income tax (recovery) expense	1,354	4,199	5,553	(43,856)	38,607	(5,249)	(2,416)	11,005	8,589	(85,139)	86,956	1,817
Net (loss) earnings	(24,590)	23,044	(1,546)	50,199	(31,541)	18,658	(59,520)	55,638	(3,882)	(167,673)	158,791	(8,882)

(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	
	June 30, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets[1]		
Canada	3,290,331	3,390,029
United States	2,316,912	2,301,353
France	715,488	801,752
Chile	1,358,671	423,856
	7,681,402	6,916,990

1. Includes the investments in joint ventures and associates.

6- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Revenues

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Revenues				
Canada	114,256	119,566	219,263	202,716
United States	62,978	26,291	106,291	102,324
France	16,065	20,832	43,461	49,200
Chile	26,447	3,916	39,454	6,016
	219,746	170,605	408,469	360,256

(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)	June 30, 2022	March 31, 2022	Dec 31, 2021	Sept 30, 2021	June 30, 2021	March 31, 2021	Dec 31, 2020	Sept 30, 2020
Production (MWh)	2,855,891	2,304,600	2,583,157	2,290,086	2,396,027	1,785,947	2,186,961	2,021,559
Revenues	219.7	188.7	202.4	184.6	170.6	189.7	167.9	162.7
Operating, general and administrative and prospective projects expenses	66.9	58.2	65.1	62.1	47.9	46.6	50.1	54.2
Adjusted EBITDA[1]	152.9	130.5	137.3	122.5	122.7	143.1	117.8	108.5
Net (loss) earnings	(24.6)	(34.9)	5.7	(23.5)	50.2	(217.9)	11.9	7.5
Net (loss) earnings attributable to owners of the parent	(25.2)	(34.4)	(2.3)	(16.4)	41.1	(214.2)	11.9	11.7
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.13)	(0.18)	(0.02)	(0.10)	0.23	(1.24)	0.06	0.06
Dividends declared on common shares	36.7	36.7	34.6	34.7	31.4	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:

		Six months ended June 30, 2021		
		As presented	Impacts from the February 2021 Texas Events (9 days)	Normalized
1	Revenues	360,256	(54,967)	305,289
	Adjusted EBITDA[1]	265,804	(54,967)	210,837
2	Change in fair value of financial instruments	(92,167)	72,060	(20,107)
3	Share of losses (earnings) of joint ventures and associates	(204,991)	64,197	(140,794)
	(Loss) Earnings before income tax	(252,812)	81,290	(171,522)

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:

	Six months ended June 30, 2021				
	Hydro	Wind	Solar	Unallocated	Total
Revenues	102,496	188,828	68,932	—	360,256
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Revenues[2]	102,496	172,027	30,766	—	305,289
Revenues Proportionate[1]	122,065	268,253	69,817	—	460,135
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Revenues Proportionate[1,2]	122,065	211,146	31,651	—	364,862
Adjusted EBITDA[1]	77,517	157,259	63,518	(32,490)	265,804
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Adjusted EBITDA[1,2]	77,517	140,458	25,352	(32,490)	210,837
Adjusted EBITDA Proportionate[1]	90,657	232,614	64,072	(32,490)	354,853
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Adjusted EBITDA Proportionate[1,2]	90,657	175,507	25,906	(32,490)	259,580

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 June 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	252,809	17,093	269,902
2	Realized loss on the Phoebe basis hedge	498	(1,304)	(806)
	Free Cash Flow[1]	76,702	15,789	92,491
	Dividends declared on common shares	125,711	—	125,711
	Payout Ratio[1]	164 %	(28)%	136 %

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 April 1, 2022, and ended on June 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 six-month period ended June 30, 2022[1]
Revenues	36,569
Net earnings	3,764
Total comprehensive income	3,764

1. Includes the combined results of Aela for a 21-day period ended June 30, 2022.

Summary Statement of Financial Position

	As at June 30, 2022
Current assets	85,310
Non-current assets	1,295,946
	1,381,256
Current liabilities	462,491
Non-current liabilities	541,714
Equity	377,051
	1,381,256

(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 this MD&A 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 June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Revenues		219,746	170,605	408,469	360,256
Expenses					
Operating		50,546	30,163	90,584	61,156
General and administrative		10,540	11,023	24,679	20,773
Prospective projects		5,788	6,734	9,808	12,523
Earnings before the following:		152,872	122,685	283,398	265,804
Depreciation	9	53,877	44,860	109,011	89,157
Amortization		25,236	14,309	50,333	28,897
Impairment of long-term assets		—	6,314	—	6,314
Earnings before the following:		73,759	57,202	124,054	141,436
Finance costs	4	77,159	58,719	143,560	118,319
Other net income	5	(18,983)	(9,325)	(39,112)	(21,229)
Share of (earnings) losses of joint ventures and associates:					
Share of (earnings) losses, before impairment charges		(1,222)	(2,993)	986	92,382
Share of impairment charges		—	—	—	112,609
Change in fair value of financial instruments	7 b)	40,041	4,458	80,556	92,167
(Loss) earnings before income tax		(23,236)	6,343	(61,936)	(252,812)
Income tax expense (recovery)		1,354	(43,856)	(2,416)	(85,139)
Net (loss) earnings		(24,590)	50,199	(59,520)	(167,673)
(Net loss) earnings attributable to:					
Owners of the parent		(25,185)	41,102	(59,587)	(173,059)
Non-controlling interests		595	9,097	67	5,386
		(24,590)	50,199	(59,520)	(167,673)
(Loss) earnings per share attributable to owners:					
Basic net (loss) earnings per share ($)	8	(0.13)	0.23	(0.31)	(1.01)
Diluted net (loss) earnings per share ($)	8	(0.13)	0.23	(0.31)	(1.01)

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 June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Net (loss) earnings		(24,590)	50,199	(59,520)	(167,673)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:					
Foreign currency translation differences for foreign operations		41,433	(6,212)	18,766	(22,880)
Change in fair value of financial instruments designated as net investment hedges	7	6,136	3,143	5,911	4,825
Change in fair value of financial instruments designated as cash flow hedges	7	104,122	(15,093)	201,924	59,246
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges		3,760	(396)	9,055	4,780
Related deferred income tax		(29,901)	969	(55,364)	(18,140)
Other comprehensive income (loss)		125,550	(17,589)	180,292	27,831
Total comprehensive income (loss)		100,960	32,610	120,772	(139,842)
Total comprehensive income (loss) attributable to:					
Owners of the parent		89,590	22,728	110,931	(146,811)
Non-controlling interests		11,370	9,882	9,841	6,969
		100,960	32,610	120,772	(139,842)

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	June 30, 2022	December 31, 2021
ASSETS			
Current assets			
Cash and cash equivalents		224,921	166,266
Restricted cash		50,969	61,659
Accounts receivable		159,002	117,906
Derivative financial instruments	7	20,930	17,024
Investment tax credits recoverable	9	1,220	1,200
Prepaid and other		44,404	24,622
Total current assets		501,446	388,677
Non-current assets			
Property, plant and equipment	9	6,122,552	5,513,392
Intangible assets		1,197,713	1,043,994
Project development costs		62,346	70,829
Investments in joint ventures and associates	6	132,304	133,398
Derivative financial instruments	7	188,824	39,917
Deferred tax assets		73,601	50,484
Goodwill		59,017	60,858
Other long-term assets		107,470	94,519
Total non-current assets		7,943,827	7,007,391
Total assets		8,445,273	7,396,068
LIABILITIES			
Current liabilities			
Accounts payable and other payables		228,025	174,364
Derivative financial instruments	7	51,248	41,315
Current portion of long-term loans and borrowings and other liabilities		368,937	517,848
Total current liabilities		648,210	733,527
Non-current liabilities			
Derivative financial instruments	7	56,245	75,064
Long-term loans and borrowings		5,298,526	4,411,239
Other liabilities		415,998	414,343
Deferred tax liabilities		457,538	401,215
Total non-current liabilities		6,228,307	5,301,861
Total liabilities		6,876,517	6,035,388
SHAREHOLDERS' EQUITY			
Equity attributable to owners		1,324,417	1,093,112
Non-controlling interests		244,339	267,568
Total shareholders’ equity		1,568,756	1,360,680
Total liabilities and shareholders’ equity		8,445,273	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

For the six-month period ended June 30, 2022	Equity attributable to owners								
	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) earnings	—	—	—	—	(59,587)	—	(59,587)	67	(59,520)
Other comprehensive income	—	—	—	—	—	170,518	170,518	9,774	180,292
Total comprehensive (loss) income	—	—	—	—	(59,587)	170,518	110,931	9,841	120,772
Common shares issued on public offering (Note 11)	172,506	—	—	—	—	—	172,506	—	172,506
Issuance fees (net of $1,979 of deferred income tax)	(5,398)	—	—	—	—	—	(5,398)	—	(5,398)
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	816	—	—	—	—	—	816	—	816
Reduction of capital on common shares (Note 11)	(560,532)	560,532	—	—	—	—	—	—	—
Buyback of common shares (Note 11)	(4,417)	—	—	—	—	—	(4,417)	—	(4,417)
Share-based payments and Performance Share Plan	—	1,776	—	—	—	—	1,776	—	1,776
Shares vested - Performance Share Plan	2,114	(4,883)	—	—	—	—	(2,769)	—	(2,769)
Shares purchased - Performance Share Plan	(3,266)	172	—	—	—	—	(3,094)	—	(3,094)
Dividends declared on common shares (Note 11)	—	—	—	—	(73,472)	—	(73,472)	—	(73,472)
Dividends declared on preferred shares (Note 11)	—	—	—	—	(2,816)	—	(2,816)	—	(2,816)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(33,070)	(33,070)
Balance June 30, 2022	1	2,580,137	131,069	2,819	(1,509,503)	119,894	1,324,417	244,339	1,568,756

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 six-month period ended June 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) earnings	—	—	—	—	(173,059)	—	(173,059)	5,386	(167,673)
Other comprehensive income	—	—	—	—	—	26,248	26,248	1,583	27,831
Total comprehensive (loss) income	—	—	—	—	(173,059)	26,248	(146,811)	6,969	(139,842)
Common shares issued through dividend reinvestment plan	2,747	—	—	—	—	—	2,747	—	2,747
Buyback of common shares	(3,414)	—	—	—	—	—	(3,414)	—	(3,414)
Share-based payments and Performance Share Plan	—	958	—	—	—	—	958	—	958
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)	177	—	—	—	—	(2,445)	—	(2,445)
Dividends declared on common shares (Note 11)	—	—	—	—	(62,877)	—	(62,877)	—	(62,877)
Dividends declared on preferred shares (Note 11)	—	—	—	—	(2,816)	—	(2,816)	—	(2,816)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(11,583)	(11,583)
Balance June 30, 2021	6,400	2,021,230	131,069	2,819	(1,282,714)	(85,448)	793,356	57,464	850,820

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 June 30		Six months ended June 30	
		2022	2021	2022	2021
OPERATING ACTIVITIES	Notes				
Net (loss) earnings		(24,590)	50,199	(59,520)	(167,673)
Items not affecting cash:					
Depreciation and amortization		79,113	59,169	159,344	118,054
Impairment of long-term assets		—	6,314	—	6,314
Share of (earnings) losses of joint ventures and associates		(1,222)	(2,993)	986	204,991
Unrealized portion of change in fair value of financial instruments	7	27,712	2,158	68,497	18,681
Production tax credits and tax attributes allocated to tax equity investors	5	(18,297)	(10,753)	(37,700)	(21,949)
Other		(240)	(79)	453	913
Finance costs	4	77,159	58,719	143,560	118,319
Finance costs paid	12 b)	(59,025)	(52,539)	(102,607)	(91,161)
Distributions received from joint ventures and associates		3,560	7,083	9,472	13,497
Income tax expense (recovery)		1,354	(43,856)	(2,416)	(85,139)
Income tax recovered (paid)		3,879	(3,115)	1,078	(3,082)
Effect of exchange rate fluctuations		(2,361)	499	(2,080)	221
		87,042	70,806	179,067	111,986
Changes in non-cash operating working capital items	12 a)	(19,414)	(21,167)	(26,581)	(2,377)
		67,628	49,639	152,486	109,609
FINANCING ACTIVITIES					
Dividends paid on common and preferred shares		(37,540)	(28,410)	(73,373)	(61,166)
Distributions to non-controlling interests		(26,906)	(10,692)	(33,070)	(11,583)
Increase in long-term debt, net of deferred financing costs	12 c)	488,286	116,673	604,099	388,571
Repayment of long-term debt	12 c)	(74,621)	(75,127)	(337,882)	(263,007)
Payment of other liabilities		(394)	(199)	(2,111)	(2,309)
Net proceeds from issuance of common shares		202	—	202,371	—
Payment for buyback of common shares		—	(3,414)	(4,417)	(3,414)
Purchase of common shares under the Performance Share Plan		(3,191)	(2,445)	(3,094)	(2,445)
Payment of payroll withholding on exercise of stock options and Performance Share Plan		—	(70)	(2,769)	(3,146)
		345,836	(3,684)	349,754	41,501
INVESTING ACTIVITIES					
Business acquisitions, net of cash acquired	3	(365,719)	—	(396,385)	—
Change in restricted cash		1,121	(489)	11,166	133
Additions to property, plant and equipment, net		(18,343)	(64,938)	(37,387)	(141,269)
Additions to intangible assets		—	—	(22)	—
Additions to project development costs		(4,492)	(5,067)	(16,907)	(12,094)
Investments in joint ventures and associates		(332)	—	(332)	(65)
Change in other long-term assets		(6,652)	(2,172)	(4,820)	(1,255)
		(394,417)	(72,666)	(444,687)	(154,550)
Effects of exchange rate changes on cash and cash equivalents		4,337	(1,034)	1,102	(4,380)
Net change in cash and cash equivalents		23,384	(27,745)	58,655	(7,820)
Cash and cash equivalents, beginning of period		201,537	181,390	166,266	161,465
Cash and cash equivalents, end of period		224,921	153,645	224,921	153,645

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 August 3, 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 have 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	19,941	25,094
Prepaid and other	389	489
Property, plant and equipment	518,188	652,087
Intangible assets	172,390	216,936
Derivative financial instruments	5,218	6,567
Deferred tax assets	15,335	19,297
Accounts payable and other payables	(3,586)	(4,513)
Long-term loans and borrowings	(371,385)	(467,351)
Other liabilities	(50,230)	(63,209)
Net assets acquired	324,348	408,159

The acquisition gave rise to transaction costs of $5,013 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 $3,043 and $4,059, respectively for the 21-day period ended June 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 June 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	30,364	38,599
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 expensed 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 $4,992 and $2,954, respectively for the 153-day period ended June 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 June 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 June 30		Six months ended June 30	
	2022	2021	2022	2021
Interest expense on long-term corporate and project loans	49,796	40,909	95,752	83,959
Interest expense on tax equity financing	7,719	4,409	14,932	10,095
Interest expense on convertible debentures	3,410	3,410	6,800	6,805
Inflation compensation interest	8,613	4,133	11,300	5,517
Amortization of financing fees	2,790	1,651	5,839	3,652
Accretion expenses on other liabilities	1,752	1,336	3,408	2,591
Interest on lease liabilities	1,684	1,019	3,159	2,034
Accretion of long-term loans and borrowings	129	116	241	274
Other	1,266	1,736	2,129	3,392
	77,159	58,719	143,560	118,319

5. OTHER NET INCOME

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Production tax credits income	(18,767)	(9,493)	(37,814)	(20,882)
Tax attributes allocated to tax equity investors income	470	(1,260)	114	(1,067)
Transaction costs related to business acquisitions	3,031	—	5,212	—
Loss on repayment of loans	—	192	—	1,317
Professional and other fees - February 2021 Texas Events	—	867	—	1,178
Realized loss on contingent considerations	—	—	—	547
Other (income) expenses, net	(3,717)	369	(6,624)	(2,322)
	(18,983)	(9,325)	(39,112)	(21,229)

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]	19,264	14,108	(88,023)	(13,846)	(68,497)
Change in fair value recognized in other comprehensive income (loss)	5,911	203,633	(1,709)	—	207,835
Amortization of accumulated other comprehensive income recognized in revenue	—	—	1,709	—	1,709
Net foreign exchange differences	—	706	(467)	13,846	14,085
As at June 30, 2022	27,660	146,532	(71,931)	—	102,261

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 June 30		Six months ended June 30	
	2022	2021	2022	2021
Unrealized portion of change in fair value of financial instruments	27,712	2,158	68,497	18,681
Realized portion of financial instruments:				
Realized loss on the power hedges	12,329	3,745	12,059	70,847
Realized loss on the interest rate swaps	—	—	—	2,885
Realized gain on Phoebe basis hedge	—	(1,445)	—	(246)
Change in fair value of financial instruments	40,041	4,458	80,556	92,167

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

8. EARNINGS (LOSS) PER SHARE

Basic	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Net (loss) earnings attributable to owners of the parent	(25,185)	41,102	(59,587)	(173,059)
Dividends declared on preferred shares	(1,407)	(1,407)	(2,816)	(2,816)
Net (loss) earnings attributable to common shareholders	(26,592)	39,695	(62,403)	(175,875)
Weighted average number of common shares	203,557,603	174,172,426	200,123,069	174,141,182
Basic net (loss) earnings per share ($)	(0.13)	0.23	(0.31)	(1.01)

Diluted	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Net (loss) earnings attributable to common shareholders	(26,592)	39,695	(62,403)	(175,875)
Diluted weighted average number of common shares	203,557,603	174,779,164	200,123,069	174,141,182
Diluted net (loss) earnings per share ($)	(0.13)	0.23	(0.31)	(1.01)

	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021
Instruments that are excluded from the dilutive elements:				
Stock options	316,922	—	316,922	262,784
Shares held in trust related to the Performance Share Plan	592,257	—	592,257	541,261
Convertible debentures	13,604,473	13,604,473	13,604,473	13,604,473
	14,513,652	13,604,473	14,513,652	14,408,518

(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	2,034	477	515	44,671	3,504	59,463
Investment tax credits [2]	—	—	—	—	(8,535)	—	(8,535)
Business acquisitions (Note 3)	53,213	—	597,265	38,595	—	1,613	690,686
Transfer from project development costs	—	—	—	—	25,034	—	25,034
Reclassification	—	—	(1,260)	—	(59)	1,319	—
Dispositions	—	(2)	(244)	—	—	(96)	(342)
Other changes	(1,437)	148	(47,287)	(12,503)	—	—	(61,079)
Net foreign exchange differences	1,530	8,379	(18,114)	11,580	1,813	51	5,239
As at June 30, 2022	246,668	2,605,339	3,422,801	857,808	135,801	51,455	7,319,872
Accumulated depreciation							
As at January 1, 2022	(16,801)	(391,093)	(549,980)	(115,531)	—	(22,609)	(1,096,014)
Depreciation [3]	(3,389)	(26,297)	(61,296)	(15,101)	—	(3,038)	(109,121)
Dispositions	—	—	195	—	—	76	271
Net foreign exchange differences	98	(245)	8,835	(1,143)	—	(1)	7,544
As at June 30, 2022	(20,092)	(417,635)	(602,246)	(131,775)	—	(25,572)	(1,197,320)
Carrying amounts as at June 30, 2022	226,576	2,187,704	2,820,555	726,033	135,801	25,883	6,122,552

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 $1,891 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 June 30, 2022, the current balance of investments tax credits recoverable, on the Hillcrest and the Hale Kuawehi projects, amounts to US$947 ($1,220), while the non current balance amounts to US$6,712 ($8,649).
3. An amount of $110 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 June 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.

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 six-month period ended June 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 proceed with a normal course issuer bid on its common and 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 six-month period ended June 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.

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 %

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

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

A compensation expense of $49 was recorded during six-month period ended June 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 six-month period ended June 30, 2022, 269,482 performance share rights vested.

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

Deferred Share Unit Plan

During the six-month period ended June 30, 2022, 25,849 units were granted.

A compensation expense of $2,107 was recorded during the six-month period ended June 30, 2022 with respect to the PSP and DSU plans.

Dividends

a) Dividend Declared

	Three months ended June 30				Six months ended June 30			
	2022		2021		2022		2021	
	($/share)	Total	($/share)	Total	($/share)	Total	($/share)	Total
Dividends declared on common shares	0.180	36,739	0.180	31,433	0.3600	73,472	0.3600	62,877
Dividends declared on Series A preferred shares	0.2028	689	0.2028	689	0.4055	1,379	0.4055	1,379
Dividends declared on Series C preferred shares	0.3594	718	0.3594	718	0.7188	1,437	0.7188	1,437

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 October 17, 2022:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
August 3, 2022	September 30, 2022	October 17, 2022	$ 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 June 30		Six months ended June 30	
	2022	2021	2022	2021
Accounts receivable	(21,919)	(26,875)	(18,711)	(28,867)
Prepaids and other	(13,048)	(2,857)	(18,587)	(6,223)
Accounts payable and other payables	15,553	8,565	10,717	32,713
	(19,414)	(21,167)	(26,581)	(2,377)

b) Additional information

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Finance costs paid relative to operating activities before interest on leases	(56,907)	(50,835)	(98,758)	(88,728)
Interest on leases paid relative to operating activities	(2,118)	(1,704)	(3,849)	(2,433)
Capitalized interest relative to investing activities	(377)	(981)	(582)	(2,010)
Capitalized interest on leases relative to investing activities	(352)	(605)	(352)	(1,183)
Total finance costs paid	(59,754)	(54,125)	(103,541)	(94,354)
Non-cash transactions:				
Change in unpaid property, plant and equipment	8,900	(20,473)	10,966	7,993
Change in other long-term assets	(10)	(30)	74	(16)
Change in unpaid project development costs	188	(770)	(1,230)	291
Remeasurement of other liabilities	(35,611)	8,197	(76,147)	(13,380)
Initial measurement of other liabilities	(69)	7,249	8,262	6,879
New obligation under financing agreement	—	19,642	—	19,642
Common shares issued through the conversion of convertible debentures	—	—	—	2,306
Common shares issued through equity based compensation	—	—	2,114	3,174
Common shares issued through dividend reinvestment plan	593	2,593	816	2,747

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

c) Changes in liabilities arising from financing activities

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Changes in long-term loans and borrowings				
Long-term debt at beginning of period	4,737,204	4,853,653	4,924,435	4,813,881
Increase in long-term debt	490,677	116,673	610,281	388,571
Repayment of long-term debt	(74,621)	(75,127)	(337,882)	(263,007)
Payment of deferred financing costs	(2,391)	—	(6,182)	—
Business acquisitions (Note 3)	467,351	—	467,351	—
Tax attributes	470	(1,260)	114	(1,067)
Production tax credits	(18,767)	(9,493)	(37,814)	(20,882)
Other non-cash finance costs	19,253	12,318	32,271	23,854
Convertible debentures converted into common shares	—	—	—	(2,306)
Accretion of convertible debentures	608	635	1,191	1,343
Net foreign exchange differences	42,221	(18,054)	8,240	(61,042)
Long-term loans and borrowings at end of period	5,662,005	4,879,345	5,662,005	4,879,345

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 June 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$26.91 to US$180.79 per MWh between July 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 July 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$303,126 ($390,608) as at June 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 June 30, 2022				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	100,119	85,638	33,989	219,746
Innergex's share of revenues of joint ventures and associates	10,387	2,557	—	12,944
PTCs and Innergex's share of PTCs generated	—	18,767	—	18,767
Segment Revenues Proportionate	110,506	106,962	33,989	251,457
Segment Adjusted EBITDA	76,377	63,418	28,488	168,283
Innergex's share of Adjusted EBITDA of joint ventures and associates	7,815	1,625	—	9,440
PTCs and Innergex's share of PTCs generated	—	18,767	—	18,767
Segment Adjusted EBITDA Proportionate	84,192	83,810	28,488	196,490
Segment Adjusted EBITDA Margin	76.3 %	74.1 %	83.8 %	76.6 %

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

Six months ended June 30, 2022				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	166,030	191,535	50,904	408,469
Innergex's share of revenues of joint ventures and associates	13,617	7,671	—	21,288
PTCs and Innergex's share of PTCs generated	—	37,814	—	37,814
Segment Revenues Proportionate	179,647	237,020	50,904	467,571
Segment Adjusted EBITDA	123,007	152,894	39,798	315,699
Innergex's share of Adjusted EBITDA of joint ventures and associates	8,955	5,822	—	14,777
PTCs and Innergex's share of PTCs generated	—	37,814	—	37,814
Segment Adjusted EBITDA Proportionate	131,962	196,530	39,798	368,290
Segment Adjusted EBITDA Margin	74.1 %	79.8 %	78.2 %	77.3 %

Six months ended June 30, 2022	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	107,129	24,462	—	131,591
Property, plant and equipment acquired through business acquisitions (Note 3)	—	598,864	38,599	637,463
Acquisition of property, plant and equipment	2,241	898	959	4,098

1. Segment totals include only operating projects.

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

Three months ended June 30, 2021				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	75,926	72,815	21,864	170,605
Innergex's share of revenues of joint ventures and associates	15,230	2,691	381	18,302
PTCs and Innergex's share of PTCs generated	—	9,493	—	9,493
Segment Revenues Proportionate	91,156	84,999	22,245	198,400
Segment Adjusted EBITDA	63,027	57,636	19,443	140,106
Innergex's share of Adjusted EBITDA of joint ventures and associates	11,633	1,895	256	13,784
PTCs and Innergex's share of PTCs generated	—	9,493	—	9,493
Segment Adjusted EBITDA Proportionate	74,660	69,024	19,699	163,383
Segment Adjusted EBITDA Margin	83.0 %	79.2 %	88.9 %	82.1 %

Six months ended June 30, 2021				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	102,496	188,828	68,932	360,256
Innergex's share of revenues of joint ventures and associates	19,569	52,509	885	72,963
PTCs and Innergex's share of PTCs generated	—	26,916	—	26,916
Segment Revenues Proportionate	122,065	268,253	69,817	460,135
Segment Adjusted EBITDA	77,517	157,259	63,518	298,294
Innergex's share of Adjusted EBITDA of joint ventures and associates	13,140	48,439	554	62,133
PTCs and Innergex's share of PTCs generated	—	26,916	—	26,916
Segment Adjusted EBITDA Proportionate	90,657	232,614	64,072	387,343
Segment Adjusted EBITDA Margin	75.6 %	83.3 %	92.1 %	82.8 %

Six months ended June 30, 2021	Hydroelectric	Wind	Solar	Segment totals [1]
Transfer of assets upon commissioning	—	14,351	—	14,351
Acquisition of property, plant and equipment	847	755	734	2,336

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 June 30, 2022				Three months ended June 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	219,746	12,944	18,767	251,457	170,605	18,302	9,493	198,400
Net (loss) earnings	(24,590)	—	—	(24,590)	50,199	—	—	50,199
Income tax expense (recovery)	1,354	—	—	1,354	(43,856)	(804)	—	(44,660)
Finance costs	77,159	4,476	—	81,635	58,719	5,210	—	63,929
Depreciation and amortization	79,113	4,222	—	83,335	59,169	5,610	—	64,779
Impairment of long-term assets	—	—	—	—	6,314	—	—	6,314
EBITDA	133,036	8,698	—	141,734	130,545	10,016	—	140,561
Other net income (expense), before PTCs	(216)	(14)	—	(230)	168	269	—	437
Production tax credits ("PTCs")	(18,767)	—	18,767	—	(9,493)	—	9,493	—
Share of (earnings) losses of joint ventures and associates	(1,222)	1,222	—	—	(2,993)	2,993	—	—
Change in fair value of financial instruments	40,041	(466)	—	39,575	4,458	506	—	4,964
Adjusted EBITDA	152,872	9,440	18,767	181,079	122,685	13,784	9,493	145,962
Unallocated expenses:								
General and administrative	9,623	—	—	9,623	10,687	—	—	10,687
Prospective projects	5,788	—	—	5,788	6,734	—	—	6,734
Segment Adjusted EBITDA	168,283	9,440	18,767	196,490	140,106	13,784	9,493	163,383
Segment Adjusted EBITDA Margin	76.6 %	72.9 %		78.1 %	82.1 %	75.3 %		82.4 %

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

	Six months ended June 30, 2022				Six months ended June 30, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	408,469	21,288	37,814	467,571	360,256	72,963	26,916	460,135
Net loss	(59,520)	—	—	(59,520)	(167,673)	—	—	(167,673)
Income tax recovery	(2,416)	—	—	(2,416)	(85,139)	(31)	—	(85,170)
Finance costs	143,560	8,900	—	152,460	118,319	14,305	—	132,624
Depreciation and amortization	159,344	8,418	—	167,762	118,054	14,565	—	132,619
Impairment of long-term assets	—	—	—	—	6,314	112,609	—	118,923
EBITDA	240,968	17,318	—	258,286	(10,125)	141,448	—	131,323
Other net income, before PTCs	(1,298)	(189)	—	(1,487)	(347)	1,870	—	1,523
Production tax credits ("PTCs")	(37,814)	—	37,814	—	(20,882)	(6,034)	26,916	—
Share of losses of joint ventures and associates	986	(986)	—	—	204,991	(204,991)	—	—
Change in fair value of financial instruments	80,556	(1,366)	—	79,190	92,167	129,840	—	222,007
Adjusted EBITDA	283,398	14,777	37,814	335,989	265,804	62,133	26,916	354,853
Unallocated expenses:								
General and administrative	22,493	—	—	22,493	19,967	—	—	19,967
Prospective projects	9,808	—	—	9,808	12,523	—	—	12,523
Segment Adjusted EBITDA	315,699	14,777	37,814	368,290	298,294	62,133	26,916	387,343
Segment Adjusted EBITDA Margin	77.3 %	69.4 %		78.8 %	82.8 %	85.2 %		84.2 %

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

Geographic segments

As at June 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 June 30		Six months ended June 30	
	2022	2021	2022	2021
Revenues				
Canada	114,256	119,566	219,263	202,716
United States	62,978	26,291	106,291	102,324
France	16,065	20,832	43,461	49,200
Chile	26,447	3,916	39,454	6,016
	219,746	170,605	408,469	360,256

As at	June 30, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,290,331	3,390,029
United States	2,316,912	2,301,353
France	715,488	801,752
Chile	1,358,671	423,856
	7,681,402	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

Refinancing of the Chilean project debt

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$ 41,196 ($53,085).

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