April 26, 2023

ENGIE ENERGÍA CHILE REPORTED EBITDA OF US$102 MILLION AND NET PROFITS OF US$20 MILLION IN THE FIRST QUARTER OF 2023.

EBITDA REACHED US$102 MILLION IN THE FIRST QUARTER OF 2023, A 49% INCREASE COMPARED TO THE FIRST QUARTER OF 2022. THE ELECTRICITY MARGIN RECOVERED DESPITE HIGH GENERATION AND SYSTEM MARGINAL COSTS, WHICH WERE AFFECTED BY THE UNAVAILABILITY OF CERTAIN COST-EFFICIENT PLANTS, THE ONGOING DROUGHT, AND STILL HIGH, THOUGH DECLINING FUEL PRICES WORLDWIDE.

- **Operating revenues** amounted to US$587.8 million in the first quarter of 2023, a 41% increase compared to the first quarter of 2022, due to an increase in physical sales to regulated clients, and the increase in average realized energy prices explained by inflation and fuel-price indices.

- **EBITDA** amounted to US$102 million in the first quarter, a 49% increase compared to the first quarter of 2022, due to the increase in operating revenues, which offset the increase in generation costs and energy purchase costs.

- **Net income** reached US$19.7 million in the first quarter of 2023, which favorably compares with net income of US$3.8 million reported in the first quarter of 2022, mainly due to the increase in the electricity margin.

Financial Highlights (in US$ millions)

	1Q22	1Q23	Var %
Total operating revenues	**417.9**	**587.8**	***41%***
Operating income	23.1	57.3	*148%*
EBITDA	**68.5**	**102.0**	***49%***
EBITDA margin	16.4%	17.3%	*(14,8pp)*
Total non-operating results	(19.7)	(30.3)	*n.a*
Net income after tax	3.8	19.7	*n.a*
Net income attributed to controlling shareholders	**3.8**	**19.7**	*n.a*
Earnings per share (US$/share)	0.004	0.019	
Total energy sales (GWh)	2,964	2,938	*-1%*
Total net generation (GWh)	1,393	1,555	*12%*
Energy purchases on the spot market (GWh)	999	552	*-45%*
Energy purchases - back up (GWh)	561	800	*43%*

ENGIE ENERGÍA CHILE S.A. ("ECL") is engaged in the generation, transmission and supply of electricity and the transportation of natural gas in Chile. ECL is the fourth largest electricity generation company in Chile and one of the largest electricity generation companies in the northern segment of the SEN national grid (formerly known as SING). As of March 31, 2023, ECL accounted for 8% of the SEN's installed capacity. ECL primarily supplies electricity to large mining and industrial customers, and it also supplies electricity to distribution companies throughout Chile. ECL is currently 59.99% indirectly owned by the French company, ENGIE LATAM. The remaining 40.01% of ECL's shares are publicly traded on the Santiago stock exchange. For more information, please refer to www.engie-energia.cl.

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HIGHLIGHTS:

SUBSEQUENT EVENTS:

- **Annual Ordinary Shareholders' Meeting**: On April 25, 2023, the Company's shareholders agreed the following:

    - **Dividend Policy:** No final dividends will be paid on account of 2022's net results given the losses reported in the period.

    - **Auditors:** To appoint EY Servicios Profesionales de Auditoría y Asesorías SpA as the Company's external auditors.

- **Financing activity:** On April 10, 2023, the company took a US$75 million short-term loan from its parent company, Engie Austral, to finance investments in fixed assets and LNG purchases. The amount may be increased to US$150 million. On April 20, the company renewed two loans with Scotiabank for a total of US$100 million, with original maturity in April and May 2023, and extended their maturity date to October 21, 2024.

- **Publication of Node Price Decree, a fundamental condition for the implementation of the PEC and MPC laws:** On April 12, 2023, the July 2022 Average Node Price Decree issued by the National Energy Commission was published in the Official Gazette. With the publication of this decree, together with the publication of the Exempt Resolution of the CNE that established the guidelines for the application of Law No. 21,472 (MPC or Consumer Protection Mechanism), the requirements for the monetization of payment certificates to be issued by the Chilean Treasury on account of the receivables to be collected from distribution companies were met. This program has been structured by IDB Invest with the collaboration of Goldman Sachs and JP Morgan and Itaú, who will support the process of selling these certificates in the international financial market. This program will allow the company to sell part of the accounts receivable originated by the energy price stabilization mechanisms, which as of March 31, 2023 reached a total of US$437 million. The company expects to sell during May 2023 a nominal amount of US$51 million in accounts receivable under the program known as PEC-1 with which it expects to raise about US$35 million after the financial discount. The remainder corresponds to the so-called PEC-2, which will be monetized through sales of certificates of payments or through monthly tariff increases in final consumers' electricity bills. The first sale of PEC-2 certificates is estimated to occur in mid-2023, as long as all conditions precedent are met.

- **Puerto Andino.** To give continuity and to enhance the profitability of our Puerto Andino port operations in Mejillones, in 2019 the company signed a strategic alliance with PASA, an experienced port operator controlled by the Sigdo Koppers group. On April 3 this alliance signed its first unloading contract through Puerto Andino with SQM. This contract will allow to receive, load, unload, transfer and store third-party cargoes. In this way, the port will be able to continue operating responsibly together with the communities, giving new uses to the company's assets, extending their life, and becoming a development opportunity for the Bay of Mejillones. Puerto Andino, in operation since 2017, has the capacity to receive more than 6 million tons of solid and liquid bulk. The terminal has a maximum allowable draft of 17.9 meters, a maximum displacement of 198,500 tons, and a design that allows the operation of capesize carriers.

RECENT EVENTS

1Q23

- **Tamaya solar PV plant**: This 114MWac plant located in the Antofagasta region achieved its commercial operation date on January 14, 2022, as confirmed by the national grid coordinator (“CEN”). This new asset forms part of our ambitious transformation plan, which considers the addition of 2GW of renewable generation and is in line with our zero carbon goals. The Tamaya plant has been injecting power to the system since November 2021.

- **Coya solar plant COD**: This 181.25 MWac solar PV plant achieved its commercial operation date (COD) on March 24, 2023, as confirmed by the National Electric Coordinator. The PV plant -located in the commune of María Elena, Antofagasta region- became the company’s largest renewable operation currently connected to the SEN power grid. With its 369,432 photovoltaic panels, it allows to supply renewable energy to the equivalent of 73 thousand homes, which means a reduction of 311,293 tons of CO2 per year. The solar energy generated by the PV plant will be stored thanks to a Battery Energy Storage System (BESS), which will have a capacity of 638 MWh. The initiative called "BESS Coya", which is currently under construction, will deliver greater efficiency and flexibility to the SEN.

- **LNG supply**: During the first quarter of 2023, the company was able to secure the purchase of liquefied natural gas for a total volume of 14 TBtu to replace the 4 cargoes for a total volume of 13.2 TBtu that its liquefied natural gas ("LNG") supplier, Total Energies Gas & Power Limited ("Total"), did not confirm, as reported by the company in the Material Fact notice issued on December 23, 2022. Through this supply of LNG, acquired at current market prices, the company has been able to reduce its exposure to the spot market and to ensure the continuous supply of energy to its customers.

- **IEM plant outage**: On January 24, the Infraestructura Energética Mejillones (IEM) power plant presented a failure in one of its auxiliary transformers, which caused malfunctioning of its electrical system. In accordance with ENGIE’s protocols, the unit’s operation was immediately halted. The initial scheduled return date was early July 2023; however, the company has taken all the necessary measures to anticipate the operational return of the plant, which could occur as soon as the first half of May 2023. The unit’s scheduled annual maintenance was anticipated to shorten the total operation stoppage period in 2023.

- **Financing activity**: During the first quarter, the company renewed US$80 million of debt maturing in February 2023, obtained a new US$50 million one-year loan and drew US$93 million from the 5-year loan granted by Banco Santander at the end of 2022 for the purchase of renewable assets in Chiloé. The company used the proceeds from the last disbursement of the Banco Santander loan to prepay the existing project financing of one of these assets a total of US$80 million.

- **S&P rating outlook**: On March 31, 2023, S&P Global Ratings placed the company’s 'BBB' rating on CreditWatch negative. In S&P's opinion, the liquidity position of Engie Energia Chile S.A. (Engie Chile) has worsened due to higher working capital requirements in 2022, and S&P believes that this situation will persist until the company is able to refinance or pay off part of its short-term debt, which reached US$360 million in December 2022. A downgrade could occur if the company fails to remedy current liquidity pressures through a refinancing strategy over the next three months. Engie Chile's debt maturity profile could improve either through the monetization of its accounts receivable originated by the tariff stabilization laws for regulated customers, a liability management program, or explicit support from its parent, Engie S.A. S&P also revised downwards the independent credit profile (SACP) of Engie Chile to 'BB' from 'BB+'. However, S&P continues to view the company as a strategically important subsidiary of Engie S.A. (Engie; BBB+/Stable/A-2), and this group support provides an up to three-notch increase to Engie Chile’s SACP rating.

- **Albemarle project**: On March 24 and 25, the transmission business unit project team reached an important milestone, performing all scheduled tasks for the energization of the new Albemarle Project facility. The project scope included the expansion of the existing Tap–Off 220/23kV Substation (owned by AES Andes), the construction of the Salar Substation within the Albemarle plant and the construction of a 35-kilometer 23 kV line to connect both substations to transmit energy to the plant for 20 years. This project involved a total of 600,000 human hours without accidents, with a peak of 180 workers in the field during the construction process.

INDUSTRY OVERVIEW

The SING and SIC power grids operated independently until November 24, 2017, when the interconnection of both grids was perfected through EECL's 50%-owned TEN project, giving birth to the SEN (*"Sistema Eléctrico Nacional"*). Currently, the company's generation assets are predominantly located in the northern segment of the SEN, in the area that used to be covered by the so-called SING Grid (*"Sistema Interconectado del Norte Grande"*), which serves a major portion of the country's mining industry. Given local conditions, the northern segment of the SEN is predominantly a thermoelectric system, with generation based on coal and LNG, with growing penetration of renewable sources, including wind, solar, and geothermal. In 2018, EECL began its geographical diversification with the acquisition of renewable generation assets in other regions of the country and with the start of supply under PPAs awarded with distribution companies in the center-south region. The interconnection of the grids and the entry into operations of the Cardones-Polpaico Interconnection Project of InterChile, on May 30, 2019, allowed for the coupling of transmission bars in the different substations of the system, reducing the curtailment of renewable energy supply due to the insufficiency of the transmission infrastructure. However, the accelerated installation of renewable energy projects in recent years has exceeded the capacity of the transmission infrastructure, making it necessary to expand it to prevent renewable energy losses.

Marginal Costs

2022	Real (Monthly Average per Node)					2023	Real (Monthly Average per Node)				
Month	**Crucero 220**	**Polpaico 220**	**Charrúa 220**	**Pto. Montt 220**	**Temuco 220**	**Mes**	**Crucero 220**	**Polpaico 220**	**Charrúa 220**	**Pto. Montt 220**	**Temuco 220**
Ene	69	69	75	213	77	**Jan**	96	94	91	197	89
Feb	68	68	69	290	72	**Feb**	114	114	110	215	107
Mar	95	102	114	210	117	**Mar**	106	133	132	207	128
Abr	108	118	126	230	127	**Abr**					
May	96	102	100	187	101	**May**					
Jun	190	200	196	224	192	**Jun**					
Jul	116	154	148	241	144	**Jul**					
Ago	101	112	100	199	90	**Aug**					
Sep	84	87	82	198	70	**Sep**					
Oct	83	69	61	77	54	**Oct**					
Nov	112	95	86	100	72	**Nov**					
Dec	96	91	89	83	61	**Dec**					
YTD	**101**	**105**	**104**	**188**	**98**	**YTD**	**105**	**114**	**111**	**206**	**108**

Source: Coordinador Eléctrico Nacional

In January 2023, marginal costs averaged US$96/MWh in the north and US$92/MWh in the center, while in the south they stood at US$197/MWh due to high temperature, transmission restrictions and higher demand.

In the first half of February 2023, there was a significant increase in marginal costs in the system (+30 US$/MWh in the north and center), due to transmission works, failures of own and third-party units, and lower hydroelectric contribution given the end of the thaw period.

During March, marginal costs reached US$106/MWh on average in the north and US$130/MWh in the center as a result of LNG purchases at market prices, while in the south they climbed to US$206/MWh due to the delay in the start of transmission works in the Araucanía region.

Fuel prices

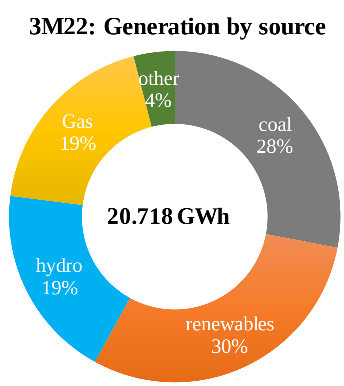
	WTI (US$/Barrel)			Brent (US$/Barrel)			Henry Hub (US$/MMBtu)			European coal (API 2) (US$/Ton)		
	2022	**2023**	**% Variation YoY**	**2022**	**2023**	**% Variation YoY**	**2022**	**2023**	**% Variation YoY**	**2022**	**2023**	**% Variation YoY**
Jan	84.3	78.1	*-7%*	86.2	82.2	*-5%*	4.32	3.18	*-27%*	167.2	167.5	*0%*
Feb	95.8	77.3	*-19%*	96.6	83.2	*-14%*	4.75	2.39	*-50%*	194.5	138.3	*-29%*
March	107.9	72.5	*-33%*	116.2	77.5	*-33%*	4.99	2.26	*-55%*	325.3	138.3	*-57%*
April	101.9			104.5			6.50			319.3		
May	111.5			114.3			8.24			328.1		
June	114.3			122.4			7.46			352.9		
July	101.2			111.6			7.37			389.0		
August	93.7			100.7			8.76			364.9		
September	85.4			89.5			7.73			328.5		
October	87.6			93.3			5.69			267.9		
November	82.8			89.9			5.45			213.6		
December	76.0			80.3			5.52			227.9		

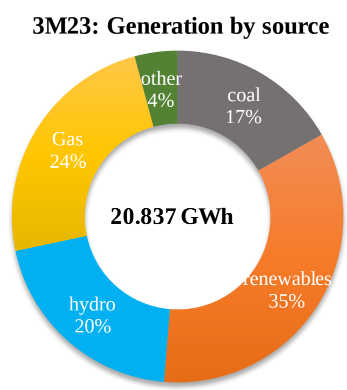
Source: Bloomberg, IEA

When comparing the first quarter of 2023 with the price trajectory in 2022, we can observe lower international fuel prices, with decreases of more than 30% on average. Fossil fuel prices depreciated sharply in early 2023, as a result of the uncertainty in the global economy and unexpected hot weather during the winter season in Europe.

Generation

The following table provides a breakdown of generation in the SEN by fuel type:





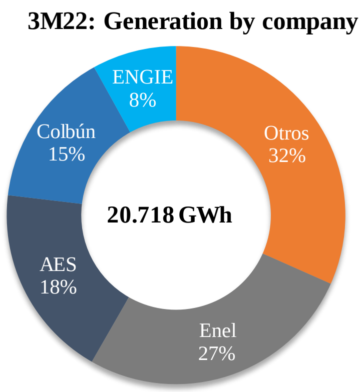
Source: Coordinador Eléctrico Nacional

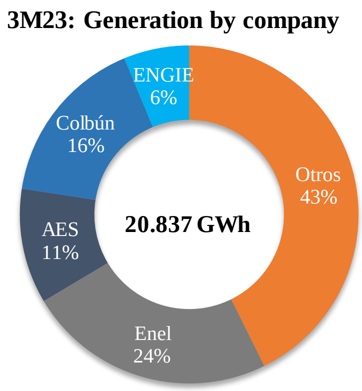
In the first quarter of 2023, demand reached a maximum of 11,492.2 MWh/h in February, 3.5% below peak demand in the first quarter of 2022. Sales reached 19,483.6 GWh in the first quarter, with a 2.9% increase in free customer sales and a 4.4% increase in the regulated client segment as compared to the first quarter of 2022.

Regarding renewable energy, solar generation increased by 19.9%, while wind generation rose by 3.2% as compared to the first quarter of 2022. As of the end of March, the National Electricity System (SEN) reported total gross installed capacity of 33,529.5, including 14,186.9 MW qualifying as non-conventional renewable energy capacity, as defined by Law #20,257.

In terms of hydraulic generation, as of April the estimated probability of exceedance for the April 2022-March 2023 hydrological year was 87%, representing an equivalent of approximately 23 TWh of energy; that is, 4 TWh more than last year. Compared to the same date of last year, energy stored in reservoirs increased by an estimated 0.9 TWh.

Electricity production in the SEN grid, broken down by company, was as follows:





Source: Coordinador Eléctrico Nacional

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following discussion is based on our unaudited consolidated financial statements for the 3-month periods ended March 31, 2023, and March 31, 2022. These financial statements have been prepared in U.S. dollars in accordance with IFRS and should be read in conjunction with the financial statements and the notes thereto published by the Comisión para el Mercado Financiero (www.cmfchile.cl).

1Q 2023 compared to 4Q 2022 and 1Q 2022

Operating Revenues

Quarterly Information (In US$ millions)

	1Q22		4Q 2022		1Q23		% Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Unregulated customers sales…………………..	177.8	49%	239.6	49%	228.6	43%	-5%	29%
Regulated customers sales…………………….	169.7	46%	219.3	45%	249.6	47%	14%	47%
Spot market sales………………………………..	18.3	5%	27.0	6%	53.5	10%	98%	193%
Total revenues from energy and capacity sales	**365.8**	88%	**485.8**	93%	**531.8**	90%	***9%***	***45%***
Gas sales…………………………..	20.1	5%	7.6	1%	25.6	4%	240%	28%
Other operating revenue……………………….	32.0	8%	27.9	5%	30.4	5%	9%	-5%
Total operating revenues………………….	**417.9**	100%	**521.3**	100%	**587.8**	100%	***13%***	***41%***
Physical Data (in GWh)								
Sales of energy to unregulated customers (1)……	1,689	57%	1,773	60%	1,655	56%	-7%	-2%
Sales of energy regulated customers……	1,126	38%	1,149	39%	1,252	43%	9%	11%
Sales of energy to the spot market……………	149	5%	18	1%	31	1%	71%	-79%
Total energy sales…………………………	**2,964**	100%	**2,940**	100%	**2,938**	100%	***0%***	***-1%***
Average monomic price unregulated customers(U.S.$/MWh)(2)	**96.7**		**135.1**		**138.1**		***2%***	***43%***
Average monomic price regulated customers (U.S.$/MWh)(3)	**150.7**		**190.8**		**199.4**		***5%***	***32%***

(2) Calculated as the quotient between unregulated and spot revenues from energy and capacity sales and unregulated and spot physical energy sales.

(3) Calculated as the quotient between regulated revenues from energy and capacity sales and regulated physical energy sales.

Energy and capacity sales reached US$531.8 million in the first quarter of 2023, representing a US$166 million, or 45%, increase compared to the first quarter of 2022. This was explained by an increase in tariffs due to increases in inflation rates and fuel prices used in contract indexation formulas and an increase in volume sales to regulated clients. The 29% increase in sales to unregulated clients was due to higher prices, which offset the 2% decrease in demand from Chuquicamata, which performed maintenance works beginning late 2022. The 47% increase in revenues from sales to regulated customers was due to higher prices, explained by higher inflation and fuel-price indices, and an increase in demand. Compared to the immediately preceding quarter, a slight decrease in volume sales to free customers could be observed.

In the first quarter of 2023, physical sales to the spot market were 31 GWh, an increase compared to the immediately preceding quarter, but a decrease from the first quarter of last year, when the subsidiaries CTH and Solar Los Loros sold their power generation in the spot market. In March 2022, supply contracts came into force under which CTH and Solar Los Loros began selling all their power generation to EECL. Spot sales in the first quarter of 2023 include the energy generated by the San Pedro 1 and San Pedro 2 wind farms in Chiloé, which sold all their energy to the spot market. Both wind farms will begin to sell all their energy to EECL under supply contracts that will become effective in the second quarter of 2023.

The increase in gas sales in the first quarter of 2023, as compared to the first and fourth quarters of 2022, is primarily explained by spot gas sales made at higher prices. The increase in gas sales was achieved despite the agreement signed with the company's main liquefied natural gas supplier in February 2022, which allowed the company to optimize annual gas purchase volumes, as well as to resolve a commercial dispute over an LNG cargo that could not be dispatched in the first half of 2021. As a result of this agreement, the company recorded a one-time US$17 million income on its operating results in the first quarter of 2022.

The most relevant items in the 'Other operating revenue' account are sub-transmission tolls and regulatory transmission revenues, which starting 2018 include a single charge called *"cargo único"*, as well as port and maintenance services.

Operating Costs

Quarterly Information (In US$ millions)

	1Q22		4Q22		1Q23		% Variation	
Operating Costs	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Fuel and lubricants……………………………………	(128.4)	*33%*	(154.9)	*31%*	(177.3)	*33%*	*14%*	*38%*
Energy and capacity purchases on the spot market……………………………	(163.0)	*41%*	(210.2)	*42%*	(219.4)	*41%*	*4%*	*35%*
Depreciation and amortization attributable to cost of goods sold…………………………….	(44.4)	*11%*	(49.9)	*10%*	(43.4)	*8%*	*-13%*	*-2%*
Other costs of goods sold…………………….	(50.5)	*13%*	(85.1)	*17%*	(83.5)	*16%*	*-2%*	*65%*
Total cost of goods sold……………….	**(386.4)**	*98%*	**(500.2)**	*100%*	**(523.5)**	*99%*	***5%***	***35%***
Selling, general and administrative expenses…	(8.7)	*2%*	(6.3)	*1%*	(8.8)	*2%*	*39%*	*2%*
Depreciation and amortization in selling, general and administrative expenses…………	(0.9)	*0%*	(1.1)	*0%*	(1.3)	*0%*	*20%*	*37%*
Other operating revenue/costs……………………….	1.3	*0%*	6.5	*-1%*	3.1	*-1%*		
Total operating costs…………………….	**(394.7)**	*100%*	**(501.1)**	*100%*	**(530.5)**	*100%*	***6%***	***34%***
Physical Data (in GWh)								
Gross electricity generation								
Coal………………………………………….	955	*63%*	687	*50%*	351	*22%*	*-49%*	*-63%*
Gas…………………………………………..	345	*23%*	289	*21%*	850	*53%*	*194%*	*146%*
Diesel Oil and Fuel Oil…………………….	1	*0%*	1	*0%*	7	*0%*	*554%*	*1188%*
Hydro/Solar/Wind……………………………….	220	*14%*	390	*29%*	407	*25%*	*4%*	*85%*
Total gross generation………………….	**1,520**	*100%*	**1,368**	*100%*	**1,615**	*100%*	***18%***	***6%***
Minus Own consumption………………..	(128)	*-8%*	(92)	*-7%*	(61)	*-4%*	*-34%*	*-53%*
Total net generation…………………….	**1,393**	***47%***	**1,275**	***42%***	**1,555**	***53%***	***22%***	***12%***
Energy purchases on the spot market………..	999	***34%***	1,081	***36%***	552	***19%***	*-49%*	*-45%*
Energy purchases- bridge………..	561	***19%***	646	***22%***	800	***28%***	*n.a*	*n.a*
Total energy available for sale before transmission losses………………………	**2,952**	***100%***	**3,002**	***100%***	**2,906**	***100%***	***-3%***	***-2%***

Renewable generation increased significantly over the periods under analysis as a result of the start of commercial operations of the Calama wind farm (151.2 MW) at the end of 2021 and the Tamaya solar PV plant (114 MWac) in early 2022, the first injections of the Capricornio solar PV plant (88 MWac) starting April 2022, and Coya (180 MWac) beginning August 2022, and the incorporation of the San Pedro wind farms in mid-December 2022. The Coya PV plant obtained its COD as of March 24, 2023.

Gross electricity generation rose by 6%, compared to the same quarter of 2022, and by 18% compared to the last quarter of 2022. The decrease in coal-based generation compared to the first quarter of 2022 was primarily due to the maintenance and failure of the IEM plant, less frequent dispatch of other coal units due to lower operating cost priority, and the closure of U15. Gas generation, which includes 314 GWh generated by BHP's Kelar unit under a tolling agreement, increased to compensate for the decrease in coal generation.

In the first quarter of 2023, the fuel cost item showed an increase compared to the immediately previous quarter as a result of the fuel mix that included the burning of coal inventory acquired at the high prices in force in the last quarter of 2022 and the use of LNG purchased at higher prices. Compared to the first quarter of 2022, the cost of fuels increased by 38%, despite the lower own generation, due to the sustained rise in fuel prices during 2022, mainly due to the Russia-Ukraine conflict, which was reflected in the operating cost of the first quarter of 2023.

The 'Cost of energy and capacity purchases' item increased by US$56.4 million (35%) compared to the same quarter of 2022. This was mainly due to higher marginal costs or average spot prices, which were offset by lower volumes of energy purchased in the spot market and the greater purchases of energy under backup contracts with other generators. The latter reached 800 GWh in the first quarter of 2023. With respect to the fourth quarter of 2022, the cost of purchasing energy and capacity rose by 4%, mainly due to the higher purchase prices in the spot market. While a decrease in the volumes of energy purchased in the spot market was observed, there was an increase in energy purchased under backup contracts and a fall in own generation. Despite an increase in the supply of water and Argentine gas supply in the system in the first quarter of 2023, marginal costs did not fall as much as expected due to failures and maintenance of efficient thermoelectric plants as well as the stock of high-priced coal that was maintained in the system.

In the first quarter, depreciation costs in the costs-of-goods-sold item decreased because of the effect of the impairment accounted for in December 2022, which impacts future depreciation.

Other direct operating costs included, among others, operating and maintenance costs, transmission tolls, insurance premiums and cost of fuels sold.

SG&A expenses decreased as compared to those reported in the first and fourth quarters of 2022.

The Other operating revenue/cost item includes water sales and miscellaneous income as well as recoveries, single charges and provisions. EECL's share in TEN's net income, which amounted to US$0.5 million in the first quarter, is also included in this item.

Electricity Margin

Quarterly Information (In US$ millions)

	2022					2023
	1Q22	**2Q22**	**3Q22**	**4Q22**	**2022**	**1Q23**
Electricity Margin						
Total revenues from energy and capacity sales………	**365.8**	**441.3**	**461.8**	**485.8**	**1,754.7**	**531.8**
Fuel and lubricants…………………..	(128.4)	(203.2)	(161.7)	(154.9)	(648.2)	(177.3)
Energy and capacity purchases on the spot market……	(163.0)	(212.0)	(213.1)	(210.2)	(798.3)	(219.4)
Gross Electricity Profit	**74.4**	**26.1**	**87.0**	**120.7**	**308.2**	**135.1**
Electricity Margin	*20%*	*6%*	*19%*	*25%*	*18%*	*25%*

In the first quarter of 2023, the electricity margin, or the gross profit from the electricity generation business, recovered, with a US$60.7 million, when compared to the first quarter of 2022, and represented 25% of energy and capacity revenues. This was because the increase in fuel and energy purchase costs was lower than the increase in energy and capacity revenues. Compared to the last quarter of 2022, the gross profit from the electricity generation business recovered by US$14.4 million, going from 18% to 25%. On the one hand, there were higher revenues from sales of energy and capacity (+US$46 million) due to the increase in the main tariff indexers (CPI and gas and coal prices). On the other hand, fuel costs increased by US$22.4 million due to higher fuel prices, and energy purchase costs increased by US$9.2 million. In short, the average cost of energy supplied rose from US$98/MWh in the first quarter of 2022 to US$135/MWh in the first quarter of 2023, a US$37/MWh increase, while average realized prices increased further by US$57.6/MWh, explaining the recovery in the electricity margin.

Operating Results

Quarterly Information (in US$ millions)

EBITDA	**1Q22**		**4Q22**		**1Q23**		**% Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Total operating revenues………………………	417.9	*100%*	521.3	*100%*	587.8	*100%*	*13%*	*41%*
Total cost of goods sold……………………	(386.4)	*-92%*	(500.2)	*-96%*	(523.5)	*-89%*	*5%*	*35%*
Gross income…………………………	**31.5**	*8%*	**21.2**	*4%*	**64.3**	*11%*	***204%***	***104%***
Total selling, general and administrative expenses and other operating income/(costs).	(8.4)	*-2%*	(0.9)	*0%*	(7.0)	*-1%*	*680%*	*-16%*
Operating income…………………	**23.1**	*6%*	**20.3**	*4%*	**57.3**	*10%*	***183%***	***148%***
Depreciation and amortization……..…………	45.4	*11%*	51.0	*10%*	44.7	*8%*	*-12%*	*-2%*
EBITDA……………….………………	**68.5**	*16.4%*	**71.3**	*13.7%*	**102.0**	*17.3%*	***43%***	***49%***

EBITDA for the first quarter of 2023 reached US$102 million, a significant recovery compared to the first and fourth quarters of 2022. The recovery was mainly due to the above-explained electricity margin increase.

Financial Results

Quarterly Information (In US$ millions)

	1Q22		**4Q22**		**1Q23**		**% Variation**	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Financial income……..………………………	1.1	*0%*	1.5	*0%*	1.3	*0%*	*-16%*	*18%*
Financial expense…………….…………………	(15.7)	*-5%*	(19.3)	*-5%*	(27.9)	*-7%*	*44%*	*78%*
Foreign exchange translation, net……………	(5.6)	*-2%*	(9.2)	*-2%*	(0.3)	*0%*		*-94%*
Other non-operating income/(expense) net…	0.5	*0%*	(447.6)	*-107%*	(3.4)	*-1%*		*-810%*
Total non-operating results…………….	**(19.7)**	*-6%*	**(474.7)**	*-114%*	**(30.3)**	*-7%*		
Income before tax……………………. ………	3.4	*1%*	(454.4)	*-109%*	27.1	*6%*	***-106%***	***697%***
Income tax………………………………………	0.4	*0%*	123.8	*30%*	(7.4)	*-2%*	*-106%*	*-1890%*
Net income from continuing operations after taxes …	3.8	*1%*	(330.6)	*-79%*	19.7	*5%*	*-106%*	*418%*
Net income to EECL's shareholders	**3.8**	*1%*	**(330.6)**	*-79%*	**19.7**	*5%*	***-106%***	***418%***
Earnings per share…………………….	**0.004**		**(0.314)**		**0.019**			

In the first quarter of 2023, interest expense increased by US$12.2 million compared to the first quarter of 2022 due mainly to (1) the increase in the company's financial debt during 2022 to finance the increase in fuel costs, the investment in renewable projects, and the build-up of accounts receivable from distribution companies related to the tariff stabilization law, and (2) the successive increase in interest rates. In the first quarter of 2023, there were no sales of accounts receivable related to the price stabilization law, whereas in the first quarter of 2022, sales of these accounts receivable caused a US$3.9 million financial expense. The US$8.6 million interest expense increase compared to the fourth quarter of 2022 is explained by higher interest rates and an increase in borrowings in the last quarter to finance the acquisition of the San Pedro wind farms in Chiloé.

Exchange rate differences reached a US$0.3 million loss in the first quarter of 2023, which compares favorably with a US$5.6 million loss in the first quarter of 2022 and a US$9.2 million loss in the fourth quarter of 2022. These fluctuations were explained by the exchange rate volatility. Fluctuations in exchange rates affect the value of certain assets and liabilities denominated in currencies other than the US dollar, the company's functional currency. These include some accounts receivable and payable, advances to suppliers, value-added tax credit and, more importantly, liabilities for onerous concessions on land and other assets recorded on the balance sheet under the IFRS16 norm.

Net Earnings

In the first quarter of 2023, the company reported net profits of US$19.7 million, a clear recovery as compared to the first quarter of 2022, when net income amounted to US$3.7 million, and the fourth quarter of 2022, when the company recorded a US$388.8 million net loss due to weaker operational results and the effects of the impairment test, which had a negative after-tax impact of -US$325 million.

Indeed, in the fourth quarter of 2022 net results were affected by non-recurring impacts, due to the recognition of the impairment in the book value of generation assets. Accounting rules (IAS 36) establish that assets must be accounted for in the balance sheet at a value not exceeding their recoverable amount. The latter is the largest of the fair value of the asset minus disposal costs and its value in use. Therefore, when the carrying amount of an asset exceeds its recoverable amount, the asset is impaired, and it must be accounted for at its recoverable amount. The recoverable value was determined by calculating EECL's equity value (EV) corresponding to discounted cash flows (hereinafter "DCF") minus net debt. The DCF methodology includes the particularities of the business plan and quantifies specific situations, such as the terms and conditions of the PPAs and the remaining useful life of the assets. The recoverability analysis must be done per cash-generating unit ("CGU"). Although the EECL business comprises a single CGU, the assets can be grouped into three different categories depending on their technologies: Thermal generation assets; renewable energy generation assets, and power transmission assets. In this case, the amount of the impairment was applied mainly to thermal assets, gas pipelines and port assets, leaving out renewable assets that are new, and transmission assets that generate flows in perpetuity. The impairment of goodwill and fixed assets will result on lower depreciation and amortization costs in the future, with a consequential positive effect on future net results. The impairment had no effect on 2022 cash flows although in the future it might cause an increase in dividend payments.

Liquidity and Capital Resources

As of March 31, 2023, EECL reported consolidated cash balances of US$130.6 million, while its nominal financial debt[1] amounted to US$1,835 million, including US$405 million of debt maturing within one year, with the following relevant debt maturity scheduled for January 2025.

For the 12-month period ended march 31 (in US$ millions)

Cash Flow	**2022**	**2023**
Net cash flows provided by operating activities…	(133.0)	43.0
Net cash flows used in investing activities………	(78.4)	(108.3)
Net cash flows provided by financing activities..	79.4	61.8
Change in cash………………...………….	**(131.9)**	**(3.6)**

Cash Flow from Operating Activities

In the first quarter of 2023, EECL reported net operating cash flows worth US$43 million, which results from the following figures: Cash flows from regular operations would have represented a net cash inflow of

(1) Nominal amounts differ from the debt amounts recorded under the IFRS methodology in the Financial Statements, which considers deferred financial expenses and mark-to-market valuations on derivative transactions. The above amount excludes the financial leases related to the long-term tolling agreement with TEN and transactions qualified as financial leases under IFRS 16.

US$179.4 million mainly due to higher energy prices and lower fuel purchases explained by the inventory build-up in late 2022. However, these cash inflows could not be fully materialized due to the lower cash collection from sales to regulated customers as a result of the price stabilization law, which resulted in a US$111.2 million build-up in accounts receivable. Therefore, the quarter's operating cash flow reached US$68.2 million, which after interest payments of US$22.5 million and income taxes of US$2.7 million, resulted in the US$43 million figure recorded as cash from operations. In the first quarter of 2022, operating cash flow was a net cash outflow of US$133 million, while the company received US$9.6 million in proceeds from the sale of accounts receivable from distribution companies related to the price stabilization law.

Cash Flow Used in Investing Activities

In the first quarter of 2023, cash flows related to investment activities resulted in a net cash outflow of US$108.3 million, mainly due to capital expenditures of US$114 million, including the BESS Coya energy storage project, the Lomas de Taltal wind farm and investments in transmission and major maintenance of generation and transmission, as detailed in the chart below. The investment in capital expenditures was partially offset by US$5.1 million positive results in financial derivatives. Cash outflows for investment activities in the first quarter of 2023 exceeded those reported in the first quarter of 2022, which amounted to US$78.4 million, including investment in the solar PV projects, Tamaya, Capricornio and Coya, the last payments for the Calama wind farm, transmission substations and plant maintenance.

Capital Expenditures

Our capital expenditures in the first quarters of 2022 and 2023 amounted to US$78.5 million and US$114.1 million, respectively, as shown in the following table. These amounts include VAT payments and capitalized interest. The latter amounted to US$1.6 million in the first quarter of 2023, whereas capitalized interest was US$1.97 million in the first quarter of 2022.

For the 3-month period march 31 (in US$ millions)

CAPEX	**2022**	**2023**
Substation…………………	4.7	15.1
Overhaul power plants & equipment maintenance and refurbishing…………………	0.8	10.6
Overhaul equipment & transmission lines	1.4	1.0
PV Power Plant……………	55.4	51.1
Wind farm……………..	9.9	33.9
Others……………………………………………	6.2	2.4
Total capital expenditures……………………….	**78.5**	**114.1**

Cash Flow from Financing Activities

In the first quarter of 2023, the main flows related to financing activities were (i) the renewal of short-term loans with BCP and Banco Santander for a total amount of US$80 million, (ii) a new US$50 million one-year loan from Banco Estado, (iii) a US$93 disbursement under the US$170 million 5-year loan granted by Banco Santander on December 15, 2022, to finance the acquisition of the San Pedro wind farms in Chiloé, and (iv) the prepayment of the long-term debt of Energías de Abtao (owner of the San Pedro II wind farm) with Banco Itaú, Banco Consorcio and Consorcio Seguros de Vida for a total amount of US$79.4 million, which EECL had assumed at the time of the acquisition of these assets in December 2022. Other payments included interest on the outstanding 144-A bonds, the Scotiabank loan, and short-term debt, which totaled US$22.2 million and were included in the cash from operations section.

In the first quarter of 2022, the main financial cash flows were the US$50 million short-term debt taken with Banco de Crédito del Perú, US$30 million in short-term loans from Banco Santander, and the payment of US$0.6 million installments under the financial lease contracts.

Contractual Obligations

The following table sets forth the maturity profile of our debt obligations as of March 31, 2023.

Contractual Obligations as of 03/31/23

Payments Due by Period (in US$ millions)

	Total	**< 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Bank debt…………………………………….……	**985.0**	405.0	37.8	433.8	108.5
Bonds (144 A/Reg S Notes)……………………..	**850.0**	-	350.0	-	500.0
Financial lease - Tolling Agreement TEN………	**53.0**	1.7	4.0	4.8	42.5
Financial lease - IFRS 16…………………………	**154.2**	8.0	13.3	9.2	123.7
Deferred financing cost…………………………..	**(16.7)**	-	(7.0)	(6.0)	(3.7)
Accrued interest…………………………………..	**22.1**	21.1	1.0	-	-
Mark-to-market swaps……………………………	**-**	-	-	-	-
Total	**2,047.6**	**435.9**	**399.0**	**441.8**	**771.0**

Notes:

a. The tolling contract signed with TEN for the use of dedicated transmission assets is considered a financial leasing operation and is accounted for under accounts payable to related companies.

b. According to the IFRS16 Leasing rules, leasing obligations for land and vehicle rentals were accounted for as financial debt.

As of March 31, 2023, the company's consolidated debt totaled US$1,835 million (US$2,042 million including IFRS 16 financial leases).

Short-term debt maturities amounted to US$443 million, including accrued interest and the current portion of financial leases. Short-term bank debt amounted to US$405 million, comprising a US$50 million loan with Banco de Crédito del Perú, due August 1, 2023, two loans totaling US$30 million with Banco Santander, due February 6, 2024, a US$50 million loan with Scotiabank due April 31, 2023, a US$20 million loan with Banco de Crédito del Perú due April 21, 2023, a US$30 million loan with Itaú maturing on April 28, 2023, a US$50 million loan with BCI due on May 21, 2023, a US$50 million loan with Scotiabank maturing on May 19, 2023, a US$25 million loan with Santander maturing May 20, 2023, a US$50 million loan with Banco de Chile maturing November 15, 2023, and a US$50 million loan with Banco Estado maturing January 31, 2024. These loans are denominated in US dollars, they accrue a fixed interest rate and are documented by a simple promissory note reflecting the repayment obligation on the agreed date, with no other operating or financial covenants, and a prepayment option at no cost for the company.

Medium and long-term bank debt reached US$580 million as of March 31, 2023 (US$125 million with BID Invest, US$250 million with Scotiabank, US$35 million with BCI, and US$170 million with Santander. The US$79.4 million loan with Itaú, Banco Consorcio and Consorcio Seguros de Vida related to the taking over of the project financing of the San Pedro II wind farm, was fully prepaid in February 2023. The outstanding loans are described in the following paragraphs.

On December 23, 2020, the Company and IDB Invest signed a financing agreement under which IDB Invest committed to extend a US$125 million loan to ENGIE Energía Chile within an initiative seeking to accelerate the decarbonization of the energy matrix in Chile. The financing includes a US$74 million senior loan from IDB Invest, a US$15 million mixed financing provided by the Clean Technology Fund (CTF), and a US$36 million loan from the China Fund for Co-financing in Latin America and the Caribbean (China Fund). The transaction, with a tenor of up to 12 years, was used to finance the construction, operation, and maintenance of the Calama wind farm. This innovative financing solution is designed to promote the acceleration of decarbonization activities by monetizing the actual displacement of CO2 emissions achieved through the anticipated decommissioning of coal-based plants whose generation will be replaced with the renewable power output of the Calama wind farm. In the absence of a carbon market, the financial structure provides for a minimum price for the avoided emissions to be paid through the reduction in the financial cost of the CTF loan. In case a carbon market is developed during the life of the loan, CTF and Engie will share any positive difference between the market price and the minimum price set at the beginning of the financing. On August 27, 2021, the company drew the full amount available under these facilities. As of March 31, 2023, the loan reported a remaining average life of 6.8 years.

On July 26, 2022, the company signed a US$250 million, 5-year bullet green financing facility with Scotiabank. The first loan under this facility, for an amount of US$150 million, was booked on July 28, and the remaining US$100 million was disbursed on September 7. The loan accrues variable interest, using the SOFR benchmark rate. To hedge against interest-rate risk, the company took interest-rate swaps with Banco de Chile for a notional amount equivalent to 70% of the facility, fixing the SOFR rate at 2.872% p.a.

On November 16, 2022, the company took a US$35 million green loan with BCI, maturing on May 22, 2024, which has the same contractual terms as the rest of the company's short-term debt.

On December 15, 2022, the company signed a 5-year credit agreement for a total committed amount of US$170 million with Banco Santander. On that date, the first US$77 million of this financing was disbursed to pay for the purchase of shares of the San Pedro wind farms in Chiloé. The remaining US$93 million was disbursed on February 15, 2023. The loan accrues interest at a variable rate based on SOFR plus a margin. To hedge interest rate risk, the company took interest rate swap derivatives with Banco Santander for a notional amount equivalent to 70% of the loan principal. Through this swap, the SOFR rate was fixed at an average rate of 3.418% p.a. for such portion of the loan.

On December 15, 2022, the company took over the project financing held by Energías de Abtao S.A. (owner of the San Pedro II Wind Farm) with Itaú, Consorcio Seguros de Vida and Banco Consorcio for a total of US$79.4 million, of which US$4.3 million was due in 2023. The company prepaid this loan with the proceeds of the second disbursement of the above-described Banco Santander loan.

EECL holds two bonds under the 144A/RegS format. The first one is a US$350 million issue with a single principal payment in January 2025 and a 4.5% p.a. coupon rate. On January 28, 2020, the company closed a new 144A/RegS issue to fully refinance the US$400 million notes originally due in January 2021. The new issue amounts to US$500 million, has a 3.4% coupon rate and is due on January 28, 2030.

Leasing obligations refer to a long-term tolling agreement signed with TEN for the use of dedicated transmission assets connecting EECL's plants in Mejillones with the national grid at the Los Changos substation. The tolling agreement is out to 20 years at which time EECL will take ownership of the asset. The agreement has a present value of US$53 million and is payable in monthly instalments totaling approximately US$7 million per year until 2037.

As of March 31, 2023, the company reported leasing obligations related to land use concessions, vehicles, and other assets for a total amount of US$154.2 million, which qualified as financial debt under the IFRS 16 accounting norm.

Dividend Policy

Our dividend policy, last approved at the Annual Ordinary Shareholders' Meeting dated April 25, 2023, consists of paying the minimum legal required amounts (30% of net income), although higher amounts may be approved if the company's conditions so allow. Our dividend payment for each year is proposed by our Board of Directors based on the year's financial performance, our available cash balance and anticipated financing requirements for capital expenditures and investments. As possible, and subject to Board approval, the company will pay provisional dividends based on the net results of the first three quarters plus the definitive dividend to be paid in May of each year.

On July 27, 2021, the company's Board approved the payment of a US$41.5 million (US$0.0393996153 per share) provisional dividend on account of 2021's net earnings. This dividend was paid on August 26, 2021. This dividend represented a distribution equivalent to 87.6% of the net income of the year 2021, so in April 2022 the board chose to propose to the Shareholders' Meeting that a definitive dividend not be distributed against the 2021 net profit in May 2022.

Considering the net loss recorded in 2022, the Ordinary Shareholders' Meeting held on April 25, 2023, approved not to distribute dividends against 2022 results.

The dividend policy proposed by our Board is subsequently approved at a Shareholders' Meeting as established by law.

The record of dividends paid since 2010 is shown in the following table:

Cash Dividends paid by Engie Energía Chile S.A.

Payment Date	Dividend Type	Amount (in US$ millions)	US$ per share
May 4, 2010	Final (on account of 2009 net income)	77.7	0.07370
May 4, 2010	Additional (on account of 2009 net income)	1.9	0.00180
May 5, 2011	Final (on account of 2010 net income)	100.1	0.09505
Aug 25 2011	Provisional (on account of 2011 net income)	25.0	0.02373
May 16 2012	Final (on account of 2011 net income)	64.3	0.06104
May 16 2013	Final (on account of 2013 net income)	56.2	0.05333
May 23 2014	Final (on account of 2013 net income)	39.6	0.03758
Sept 30,2014	Provisional (on account of 2014 net income)	7.0	0.00665
May 27 ,2015	Final (on account of 2014 net income)	19.7	0.01869
Oct 23 ,2015	Provisional (on account of 2015 net income)	13.5	0.01280
Jan 22, 2016	Provisional (on account of 2015 net income)	8.0	0.00760
May 26, 2016	Final (on account of 2015 net income)	6.8	0.00641
May 26, 2016	Provisional (on account of 2016 net income)	63.6	0.06038
May 18, 2017	Final (on account of 2016 net income)	12.8	0.01220
May 22,2018	Final (on account of 2017 net income)	30.4	0.02888
Oct 25 ,2018	Provisional (on account of 2018 net income)	26.0	0.02468
May 24 ,2019	Final (on account of 2018 net income)	22.1	0.02102
June 21 ,2019	Provisional (on account of 2019 net income)	50.0	0.04747
Dec 13 ,2019	Provisional (on account of 2019 net income)	40.0	0.03798
Nov 30 ,2020	Provisional (on account of 2020 net income)	66.6	0.06323
May 20 ,2021	Final (on account of 2020 net income)	51.1	0.04847
Aug 26 ,2021	Provisional (on account of 2021 net income)	41.5	0.03940

Risk management policy

The energy sector is subject to diverse and changing economic, political, regulatory, social and competitive conditions. In the normal course of business, EECL is exposed to several risk factors that may impact its operating and financial performance. Risk factors are monitored closely and periodically by each risk owner of the different business processes and are coordinated by the Planning and Business Control Areas of the company. The company's financial risk management strategy seeks to safeguard EECL's operating stability and sustainability in a context of risk and uncertainty.

EECL has established risk management procedures, which include a description of the risk assessment methodology and risk analysis, including the construction of a risk matrix called Enterprise Risk Management ("ERM"), which is updated and reviewed once a year. The progress of each action plan and the update of the risks are carried out permanently within the ERM framework, which aims to preserve and continuously improve the value, reputation and internal motivation, promoting a reasonable risk-taking in social, human, and legal terms, acceptable to stakeholders and economically sustainable.

Risk management is presented to the Board annually. The Company's financial risk management strategy is aimed at safeguarding the stability and sustainability of ENGIE Energía Chile in relation to all those components of financial uncertainty or relevant risk events.

Hedging Policy

Our hedging policy intends to protect the company against our exposure to certain risks, as follows:

Business Risk and Commodity Hedging

We import a significant portion of our fuel supply through short, medium and long-term contracts, making us vulnerable to potential supply shortfalls or defaults by our suppliers. We also source a significant portion of coal, natural gas and other fuels from a limited number of suppliers. If any of our relevant suppliers were to experience disruption in their production chain or were unable to meet their obligations under supply contracts, we may be forced to purchase at higher prices, either the same fuel or a substitute, and we may be unable to adjust the price of electricity sold according to the tariff adjustment mechanisms included in our contracts with customers, with the consequent reduction in our operating margins. This risk has materialized at the beginning of 2023 due to the fact that the main supplier of liquefied natural gas has not confirmed the provision of supply for the year 2023 under one of the long-term contracts for a total volume close to 13.2 TBtu, exposing the company to seek alternative sources of fuel supply and to initiate legal actions.

We are exposed to commodity price volatility since electricity generation activities require continued supply of fossil fuels, mainly coal, gas and diesel oil, with international prices that fluctuate according to market and political variables beyond the company's control. Coal purchases are mostly made through annual contracts, the prices of which are linked to traditional indices such as API 2, API 10 or Newcastle. Purchases of diesel oil and certain purchases of liquefied natural gas are made at prices based on international oil values (ULSD or Brent). The company has long-term liquefied natural gas purchase contracts with prices tied to Henry Hub.

Fuel prices are a key factor for the dispatch of thermoelectric generation plants, the company's average generation cost and the marginal costs of the electricity system in which it operates. Therefore, our business is subject to the risk of variations in the availability of fuels and their prices. Historically, our policy has been to hedge as much as possible against these risks through the indexation of the energy tariffs incorporated in our PPAs, and the fuel mix taken into consideration in the tariffs. However, given (i) the volume fluctuations that our PPAs may have; (ii) the variability that our plant dispatch profile may experience; (iii) our inability to perfectly match at all times our fuel cost mix with the tariff indexation in our PPAs; and (iv) the growing trend to dissociate PPA price indexation from fossil fuel price fluctuations, we maintain residual exposure to certain international commodity prices. For example, as a result of our decarbonization strategy, the tariff indexation of several of our PPAs has been switched from coal prices to US CPI beginning 2021 or 2022, as the case may be. This assumes power supply based on renewable sources or energy purchases at prices linked to inflation rather than fuel prices. As long as we have a mismatch in the indexation of our power sources and our PPA tariffs, we will have exposure to commodity price fluctuations. In the past, the company has periodically defined and executed financial hedging strategies to cover its residual exposure to international commodity price risks and is in the process of defining a hedging strategy for 2023-24. During 2021, and with greater intensity in the course of 2022, this risk has materialized. In our country, the hydrological year has been extremely dry, with the consequent decrease in hydraulic generation. This has coincided with difficulties in the supply of coal and natural gas due to the rise in demand together with restrictions on the world production of these fuels, as well as difficulties in freight, which resulted in price increases to very high levels even before the start of the war between Russia and Ukraine that raised prices to levels never seen before. Consequently, the average costs of own generation and the marginal costs of the system have reached levels much higher than those of previous years, which have been reflected in the reduction of the operating margins of the electricity business. The Company partially mitigates its exposure to the risk of fluctuations in fuel prices through (i) the signing of supply contracts with other generators in the system that have allowed it to reduce its energy purchases from the spot market (3.2 TWh contracted for 2023, versus 2.1 TWh for 2022 and 0.7 TWh in 2021) and its exposure to marginal cost; (ii) its long-term LNG supply contracts; (iii) the entry into operations of new renewable energy generation projects that reduce dependence on fossil fuels, (iv) the acquisition of uncontracted renewable generation assets, and (v) the transfer of higher costs to final tariffs.

Foreign Currency Hedging

Given that most of our revenues and costs are denominated in US dollars and that we seek to incur debt in US dollars, we face limited exposure to foreign exchange risk. In the specific case of regulated contracts, the price is calculated in US dollars and is then converted to Chilean pesos at the average monthly exchange rate observed in the invoiced month. In terms of the impact on the company's income statement, these contracts' exposure to foreign currency risk is limited as revenues are recognized at contract prices. However, delays in the publication of the Average Node Price decrees may impact the company's cash flow as monthly invoices are translated to Chilean pesos at exchange rates that remain fixed over the life of the tariff decree and differ from the monthly exchange rates considered in the contracts. Although these differences are adjusted after the Average Node Price decrees are published, the uncertainty as to the timing and amount of these adjustments does not allow for an effective hedge through derivative instruments. The delay in the collection of foreign-exchange adjustments has significantly increased after the approval of the Price Stabilization law in November 2019 and the MPC law published in August 2022. Per the Price Stabilization law and resolution #72, by which the National Energy Commission set the terms of its implementation, accounts receivable from distribution companies have accumulated at a rate that is highly sensitive, among other variables, to the CLP/USD exchange rate. To face this risk and mitigate its effect on the company's cash flow and liquidity, the company, and its subsidiary EMR, signed agreements with Goldman Sachs and IDB Invest to sell, without recourse, these accounts receivable from distribution companies to a special purpose company called Chile Electricity PEC SpA. On January 29, 2021, Chile Electricity PEC issued 144 A/Reg S bonds for US$489 million to buy the first two groups of accounts receivable from the four main generation groups in Chile, including ENGIE. On June 30, 2021, Chile Electricity PEC purchased the third group of accounts receivable from generation companies with funds provided by US$419 million 4a2 delayed draw notes with the participation of Allianz, IDB Invest and Goldman Sachs. Upon the publication of the respective node price decrees, similar transactions were perfected on March 4, 2022, for the fourth group of accounts receivable and July 14, 2022, for the fifth group. Since the sale of receivables is made in US dollars, without recourse to the generation companies, EECL and EMR have been able to reduce the foreign-exchange and credit exposure associated to these long-term accounts receivable and have improved their liquidity in exchange for a discount, which has impacted the income statement in 2021 and 2022, and is expected to affect 2Q23 results. In 2021, the related financial expense reached US$49.6 million, while in 2022, it amounted to US$15.6 million. As the Average Node Price Decree – July 2022 was recently published, the company expects to sell the remaining US$51 million accounts receivable under the PEC-1 mechanism in May 2023, with associated financial expenses of approximately US$14 million.

Our main cost in Chilean pesos is personnel and certain operating and administrative costs, which account for approximately 10% of our operating costs. Given that most of our revenues are either in US dollars or in Chilean pesos adjusted for the exchange rate, our costs in Chilean pesos represent our main exposure to foreign-currency risks. Therefore, we have hedged a portion of our recurrent costs in Chilean pesos through forward contracts. As of March 31, 2023, the Company reported forward FX contracts for a total nominal amount of US$81 million, with monthly maturities of US$9 million between April and December 2023, to mitigate the impact of foreign exchange fluctuations on the company's financial results. In addition, the company has entered into cash flow hedging derivative contracts associated with payments under EPC contracts related to project construction, which typically consider periodic payment flows in currencies other than the dollar (CLF, EUR) until the end of the respective project construction periods. In this way, the company has avoided variations in the cost of investment in fixed assets as a result of fluctuations in exchange rates beyond its control. Currently, there are forward dollar sales contracts for a total notional amount of US$77 million to cover periodic payments in UF to contractors of the Lomas de Taltal project. These derivatives were taken with Banco de Chile and cover periodic payment flows between March 2023 and March 2025.

Our cash investment policy states that at least 80% of cash balances must be invested in US dollars unless a different percentage is required to maintain a natural currency hedge between assets and liabilities. This policy allows for the necessary flexibility to achieve a natural hedge for obligations in currencies other than the company's functional currency, the US dollar. As of March 31, 2023, 84.6% of our available cash and short-term investments were denominated in US dollars.

The Company presents an exposure to foreign exchange risk of a purely accounting nature related to contracts for onerous concessions or other types of contracts such as real estate or vehicle fleet leases that are considered as financial leases under the IFRS16 standard. These contracts comprise assets for rights of use that correspond to non-monetary assets, recorded at their initial cost, in dollars, the company's functional currency. Their counterparts correspond to monetary liabilities reflecting the present value of the installments to be paid under the financial contracts. Most of these liabilities are denominated in Chilean currency, adjusted for inflation (*Unidades de Fomento (UF) or Unidades Tributarias (UTM)*). As these are monetary liabilities, they are periodically readjusted and converted into dollars at the exchange rate observed at the end of each accounting period. In short, the liability denominated in CLP, UF or UTM is subject to periodic readjustments, being exposed to fluctuations in exchange rates, while the asset remains fixed in dollars. This mismatch may give rise to accounting profits or losses in our income statements. However, financially, the value of the asset for rights of use is closely related to the value of the liability since both should reflect the present value of the installments payable under the financial contracts. As of March 31, 2023, lease liabilities denominated in currencies other than the dollar amounted to US$154.2 million.

Interest Rate Hedging

The stability and predictability of our cash flows is also exposed to interest rate risk, principally with respect to the portion of our indebtedness that bears interest at floating rates. We seek to maintain a significant portion of our long-term debt at fixed rates to minimize interest-rate exposure. As of March 31, 2023, 87.1% of our financial debt was at fixed rates, while 12.9% (US$110 million of the IDB Invest financing, US$75 million of the Scotiabank loan, and US$51 million of the Santander loan) was at floating rates. We have excluded the IFRS 16 financial leases from this calculation. These obligations are mortgage-style liabilities payable in fixed equal installments.

As of March 31, 2023

Contractual maturity date (in US$ millions)

	Average interest rate	2023	2024	2025	2026	Thereafter	Grand Total
Variable Rate							
(US$)	7.2057% p.a.	-	-	2.8	5.0	102.3	110.0
(US$)	5.9327% p.a.	-	-	-	-	75.0	75.0
(US$)	7.1968% p.a.	-	-	-	-	51.0	51.0
Total Variable Rate		**-**	**-**	**2.8**	**5.0**	**228.3**	**236.0**
Fixed Rate							
(US$)	4.8770% p.a.	405.0	-	-	-	-	405.0
(US$)	7.3000% p.a.	-	35.0	-	-	-	35.0
(US$)	5.9680% p.a.	-	-	-	-	119.0	119.0
(US$)	1.0000% p.a.	-	-	-	-	15.0	15.0
(US$)	4.0910% p.a.	-	-	-	-	175.0	175.0
(US$)	3.4000% p.a.	-	-	-	-	500.0	500.0
(US$)	4.5000% p.a.	-	-	350.0	-	-	350.0
Total Fixed Rate		**405.0**	**35.0**	**350.0**	**-**	**809.0**	**1,599.0**
TOTAL		**405.0**	**35.0**	**352.8**	**5.0**	**1,037.3**	**1,835.0**

Credit Risk

In the normal course of business, and when investing our cash, we are exposed to credit risk. In our regular electricity generation business, we deal mostly with financially strong mining companies, which report low levels of credit risk. These companies are exposed to variations in commodity prices, particularly copper. Although our clients have demonstrated significant resilience to down-cycles, we closely monitor their exposure through our commercial counterparty risk policy.

We also sell electricity to regulated clients, which provide electricity supply to residential and commercial clients and report low levels of credit risk. Lower growth in energy demand from end consumers could adversely affect our financial condition, operating results and cash flows. While the Electricity Price Stabilization Law enacted in November 2019 is not expected to significantly affect our revenues as recognized in the income statement, it has been affecting our cash flow with higher working capital requirements and higher financial costs. To address this risk and mitigate the effects on its cash flow, in early 2021, the company signed agreements with Goldman Sachs and IDB Invest to sell, without recourse to the company, these receivables to a special purpose company called Chile Electricity PEC SpA. On February 8, March 31 and June 30, 2021, the Company sold the accounts receivable corresponding to the Average Note Price decrees of January 2020, July 2020, and January 2021, respectively, for a total nominal value of US$167.3 million, receiving liquid resources of US$118.6 million and reporting a financial cost of US$49.6 million. On March 4 and July 14, 2022, the Company sold the accounts receivable corresponding to the Average Node Price decrees of July 2021 and January 2022 for a total nominal value of US$54.8 million, receiving a US$39.3 million cash payment and reporting a US$15.5 million financial cost. The remainder to be sold under PEC-1, corresponding to the balances stipulated in the Average Node Price decree of July 2022, which was published in the Official Gazette in April 2023, will allow the company to sell balances of approximately US$51 million. With the enactment of the MPC Act, accounts receivable have continued to be generated for the differential between the stabilized price (PEC) and the PPA price. With the publication of the Average Node Price decree of July 2022 and the Exempt Resolution that will lay the foundations for the effective application of the Law, the Treasury will issue Payment Certificates that the Company may sell under a mechanism similar to the one implemented for the PEC law, but this time without assuming costs for financial discounts. The deferral in the collection of accounts receivable resulting from the delay in the publication of decrees has significantly affected the company’s liquidity and indebtedness.

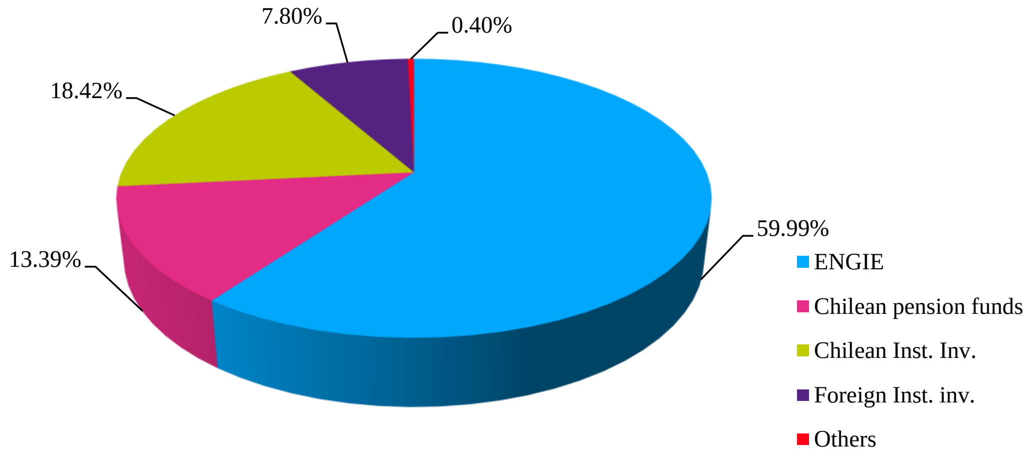
Over the last years, the electricity generation business and its customer base have evolved. Particularly, consumers with demand between 500 kW and 5 MW are allowed to contract their power supply directly with generation companies rather than through distribution companies. This disintermediation trend led us to sign contracts with smaller commercial and industrial clients with potentially higher credit risk. To mitigate this risk, we have implemented a commercial counterparty risk policy, which among other considerations, requires the review of the credit risk of the client before entering into a power supply agreement. As of March 31, 2023, the contracts signed with smaller commercial and industrial clients represented a low percentage of our overall client portfolio, and the company stopped actively marketing this segment in order to balance its contract portfolio and reduce its short position in the energy spot market.

Due to its contractual position, the company is normally one of the main net payers within the payment chain of the Chilean electricity sector. Although it is exposed to delinquencies or defaults by operators in the electricity sector, these amounts represent a relatively smaller percentage of monthly collections. Non-compliance by other electricity system operators could expose the Company to increasing sales volumes to regulated customers at the prices of its existing contracts.

Our cash management policy is to invest in investment-grade institutions only, and only within the short term. We also measure our counterparty risk when dealing with derivatives and guarantees, and we have individual counterparty limits to manage our exposure and ensure proper diversification of our credit risk.

OWNERSHIP STRUCTURE AS OF MARCH 31, 2023

NUMBER OF SHAREHOLDERS: 1,758



TOTAL NUMBER OF SHARES: 1,053,309,776

APPENDIX 1

PHYSICAL DATA AND SUMMARIZED QUARTERLY FINANCIAL STATEMENTS

Physical Sales

Physical Sales (in GWh)

	2022					2023
	1Q22	2Q22	3Q22	4Q22	12M22	1Q23
Physical Sales						
Sales of energy to unregulated customers.	1,689	1,816	1,796	1,773	7,074	1,655
Sales of energy to regulated customers	1,126	1,204	1,255	1,149	4,735	1,252
Sales of energy to the spot market………	149	23	48	18	238	31
Total energy sales…………………………	**2,964**	**3,043**	**3,100**	**2,940**	**12,047**	**2,938**
Gross electricity generation						
Coal………………………………………….	955	1,085	775	687	3,503	351
Gas…………………………………………..	345	423	382	289	1,439	850
Diesel Oil and Fuel Oil…………………….	1	17	1	1	19	7
Renewable……………………………………….	220	226	303	390	1,139	407
Total gross generation.………………….	**1,520**	**1,751**	**1,461**	**1,368**	**6,100**	**1,615**
Minus Own consumption………………..	(128)	(136)	(152)	(92)	(507)	(61)
Total net generation.…………………….	**1,393**	**1,615**	**1,310**	**1,275**	**5,593**	**1,555**
Energy purchases on the spot market………..	999	1,114	1,308	1,081	4,501	552
Energy purchases- bridge	561	430	497	646	2,134	800
Total energy available for sale before transmission losses………………………	**2,952**	**3,159**	**3,115**	**3,002**	**12,228**	**2,906**

Quarterly Income Statement

Quarterly Income Statement (in US$ millions)

IFRS						
Operating Revenues	1Q22	2Q22	3Q22	4Q22	12M22	1Q23
Regulated customers sales………………………	169.7	178.5	205.3	219.3	772.8	249.6
Unregulated customers sales…………………..	177.8	230.7	229.5	239.6	877.7	228.6
Spot market sales………………………………..	18.3	32.0	26.9	27.0	104.2	53.5
Total revenues from energy and capacity sales…………………	**365.8**	**441.3**	**461.8**	**485.8**	**1,754.7**	**531.8**
Gas sales…………………………..	20.1	9.5	11.8	7.6	48.9	25.6
Other operating revenue……………………….	32.0	30.7	26.2	27.9	116.7	30.4
Total operating revenues…………………	**417.9**	**481.4**	**499.7**	**521.3**	**1,920.3**	**587.8**
Operating Costs						
Fuel and lubricants………………………………	(128.4)	(203.2)	(161.7)	(154.9)	(648.2)	(177.3)
Energy and capacity purchases on the spot	(163.0)	(212.0)	(213.1)	(210.2)	(798.3)	(219.4)
Depreciation and amortization attributable to cost of goods sold..	(44.4)	(44.0)	(46.9)	(49.9)	(185.3)	(43.4)
Other costs of goods sold…………………….	(50.5)	(65.9)	(67.6)	(85.1)	(269.1)	(83.5)
Total cost of goods sold………………..	**(386.4)**	**(525.2)**	**(489.3)**	**(500.2)**	**(1,901.0)**	**(523.5)**
Selling, general and administrative expenses…	(8.7)	(9.6)	(9.2)	(6.3)	(33.8)	(8.8)
Depreciation and amortization in selling, general and administrative expenses…	(0.9)	(0.9)	(1.1)	(1.1)	(4.1)	(1.3)
Other revenues………..………………………	1.3	1.3	9.2	6.5	18.3	3.1
Total operating costs…..………………	**(394.7)**	**(534.4)**	**(490.4)**	**(501.1)**	**(1,920.6)**	**(530.5)**
Operating income…..………………	**23.1**	**(53.0)**	**9.2**	**20.3**	**(0.3)**	**57.3**
EBITDA………………..………………	**68.5**	**(8.0)**	**57.3**	**71.3**	**189.0**	**102.0**
Financial income………..………………………	1.1	0.7	13.5	1.5	16.8	1.3
Financial expense…………….…………………	(15.7)	(13.0)	(27.4)	(19.3)	(75.5)	(27.9)
Foreign exchange translation, net……………	(5.6)	4.0	(3.9)	(9.2)	(14.7)	(0.3)
Other non-operating income/(expense) net………………………	0.5	0.1	(0.6)	(447.6)	(447.7)	(3.4)
Total non-operating results……………	**(19.7)**	**(8.3)**	**(18.4)**	**(474.7)**	**(521.1)**	**(30.3)**
Income before tax…………………..………	3.4	(61.3)	(9.1)	(454.4)	(521.4)	27.1
Income tax………………………………………	0.4	17.1	(8.6)	123.8	132.7	(7.4)
Net income from continuing operations after taxes …….	3.8	(44.2)	(17.8)	(330.6)	(388.8)	19.7
Net income attributed to controlling shareholders………………	**3.8**	**(44.2)**	**(17.8)**	**(330.6)**	**(388.8)**	**19.7**
Net income to EECL's shareholders…….	**3.8**	**(44.2)**	**(17.8)**	**(330.6)**	**(388.8)**	**19.7**
Earnings per share…………………….. (US$/share)	**0.004**	**(0.042)**	**(0.017)**	**(0.314)**	**(0.369)**	**0.019**

Quarterly Balance Sheet

Quarterly Balance Sheet (in U.S.$ millions)

	2022 December	2023 March
Current Assets		
Cash and cash equivalents	132.4	130.6
Accounts receivable	226.1	270.6
Recoverable taxes	35.2	34.9
Current inventories	264.1	246.9
Other non financial assets	178.1	230.7
Total current assets	**835.8**	**913.7**
Non-Current Assets		
Property, plant and equipment, net	2,576.6	2,625.7
Other non-current assets	915.8	1,016.3
TOTAL ASSETS	**4,328.3**	**4,555.7**
Current Liabilities		
Financial debt	389.5	434.1
Other current liabilities	270.7	405.0
Total current liabilities	**660.2**	**839.1**
Long-Term Liabilities		
Financial debt	1,579.5	1,611.8
Other long-term liabilities	274.6	272.0
Total long-term liabilities	**1,854.1**	**1,883.8**
Shareholders' equity	1,813.9	1,832.7
Equity	**1,813.9**	**1,813.9**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**4,328.3**	**4,555.7**

Main Balance Sheet Variations

The main balance-sheet variations between December 31, 2022, and March 31, 2023, are the following:

Cash and cash equivalent: The company's cash balances decreased by just US$1.7 million to a US$130.6 million balance as of March 31, 2023, mainly because of (i) net operating cash flows (US$68.2 million), (ii) interest payments (US$23.9 million), (iii) income tax payments (US$2.7 million), (iv) capital expenditures (US$114 million), and (v) a US$61.8 million net debt increase.

Accounts receivable: The US$44.5 million increase comprises changes in three different accounts: On the one hand, accounts receivable from third parties reported a US$44.1 million increase mainly due to higher tariffs and because certain relevant invoices were collected ahead of their maturity in December 2022. On the other hand, intercompany receivables, mainly those from Engie Gas, increased by US$4.9 million. Finally other accounts receivable, including personnel accounts, dropped by US$4.5 million.

Current inventories: The US$17.2 million decrease in this item is explained by a US$47.3 million drop in coal and limestone inventory, following the increase observed in 2022 explained by both price and volume increases. In the second half of 2022, the company decided to increase inventory stocks given the uncertain market context at the time. The US$28.5 million increase in LNG inventory is also due to higher prices in addition to volume variations related to the arrival date of shipments and the cut-off date of the financial statements. Impairments and obsolescence provisions remained at similar levels reaching a total of -US$66.4 million.

Recoverable taxes: This item showed no significant variations. Taxes to be recovered from previous years amounted to US$32.5 million at the end of March due to the drop in taxable income and the use of instant depreciation in the projects activated in recent years.

Other non-financial assets – current: The US$52.6 million increase in this item is explained by a US$38 million increase in the VAT fiscal credit balance due to the increase in fuel purchases and capital expenditures in new projects, as well as by a US$13.2 million increase in advances to suppliers, and the positive mark-to-market of financial derivatives which increased by US$7.8 million in the first quarter of 2022. This was partially offset by a US$6.8 million decrease in anticipated expenses.

Property, plant and equipment, net: The US$49.1 million increase in PP&E was explained by capital expenditures related to investments in renewable energy and transmission projects (US$59.6 million), which were offset by depreciation of US$44 million.

Other non-current assets: The US$100.5 million net increase in this item resulted primarily from a US$111.2 million increase in long-term accounts receivable associated to the enactment of the price stabilization law and a US$1.6 million increase in project development expenses. This was offset by a US$28.9 million decrease in deferred taxes, a US$5.7 million decrease in the book value of the company's equity share in TEN mainly driven by the variation in the market valuation of risk-coverage derivatives, and a US$1.7 million decrease in the recognition of assets by right of use, mainly onerous concessions on land for the renewable projects (IFRS16).

Financial debt – current: This item reported a US$44.6 million increase due to a new US$50 million loan with Banco Estado and an increase in accrued interest driven by the increase in both debt levels and interest rates.

Other current liabilities: The US$134.3 million net increase in this item is explained by (i) a US$74.8 million increase in accounts payable to suppliers, (ii) a US$65.2 million increase in intercompany payables, primarily GEMS, related to an LNG shipment, and (iii) a US$5.4 million increase in income tax provisions. These increases were partially offset by a US$10.2 million decrease in provisions related to employee benefits following the payment of annual performance bonuses in 1Q23.

Long-term financial debt: The US$32.3 million increase in this account is mainly explained by the second disbursement under the 5-year loan with Banco Santander amounting to US$93 million, combined with the prepayment of the San Pedro 2 wind farm project financing, which explains a US$75.1 million decrease in the long-term portion of financial debt. An additional US$10.6 million debt increase is explained by foreign exchange adjustments of financial lease liabilities associated primarily with onerous concessions on land for the development of renewable energy generation projects.

Other long-term liabilities: Other long-term liabilities, which amounted to US$272.1 million, reported a US$2.5 million decrease due to a US$3.1 million decrease in deferred tax liabilities.

Shareholders' equity: The US$18.8 million increase in shareholders' equity is primarily explained by the US$19.7 million net income reported in 1Q23.

APPENDIX 2

Financial information

	1Q21	2Q21	3Q21	4Q21	1Q22	2Q22	3Q22	4Q22	1Q23
EBITDA*	65.9	121.7	55.6	71.3	68.5	-8.0	57.3	71.3	102.0
Net income attributed to the controller	-17.6	47.6	8.7	8.7	3.8	-44.2	-17.8	-330.6	19.7
Interest expense	52.2	16.8	8.9	10.9	15.7	13.0	27.4	19.3	27.9

* Operating income + Depreciation and Amortization for the period

	Dec-21	Dec-22	Mar-23
LTM EBITDA	314.5	189.0	222.5
LTM Net income attributed to the controller	47.4	(388.8)	(372.9)
LTM Interest expense	88.8	75.5	87.7
Financial debt	1,258.6	1,969.0	2,045.9
Current	106.2	389.5	434.1
Long-Term	1,152.4	1,579.5	1,611.8
Cash and cash equivalents	215.7	132.4	130.6
Net financial debt	1,042.9	1,836.6	1,915.3

Financial Ratios

	FINANCIAL RATIOS				
			Dec-22	Mar-23	Var.
LIQUIDITY	Current ratio (current assets / current liabilities)	(times)	1.27	1.09	***-14%***
	Quick ratio ((current assets - inventory) / current liabilities)	(times)	0.87	0.79	***-8%***
	Working capital (current assets – current liabilities)	MMUS$	175.6	74.6	***-58%***
LEVERAGE	Leverage ((current liabilities + long-term liabilities) / networth)	(times)	1.39	1.50	***8%***
	Interest coverage * ((EBITDA / interest expense))	(times)	2.50	2.54	***1%***
	Financial debt –to- LTM EBITDA*	(times)	10.42	9.19	***-12%***
	Net financial debt – to - LTM EBITDA*	(times)	9.72	8.61	***-11%***
PROFITABILITY	Return on equity* (LTM net income attributed to the controller / net worth attributed to the controller)	%	-21.4%	-20.3%	***-5%***
	Return on assets* (LTM net income attributed to the controller / total assets)	%	-9.0%	-8.2%	***-9%***

*LTM = Last twelve months

As of March 31, 2023, the current ratio and the quick ratio were 1.09x and 0.79x, respectively, reflecting an increase in current assets and in current liabilities. The latter increased more due to the increase in financial debt and in trade payables. As a result, working capital, as measured by total current assets minus total current liabilities, decreased.

The leverage ratio, as measured by total liabilities-to-equity, increased to 1.50x as a consequence of the debt increase combined with the impairment carried out at year-end 2022, which caused net losses and a reduction in networth.

The interest coverage ratio for the 12 months ended on March 31, 2023, was 2.54x, which represents an improvement compared to 2.50x reported at year-end 2022, mainly due to the EBITDA recovery in the first quarter, which offset the effect of higher interest expenses.

The leverage ratio, as measured by Gross financial debt-to-EBITDA, increased to 9.19 times, including IFRS 16 financial leases, due to the increase in debt combined with the drop in EBITDA in 2022. Net financial debt-to-EBITDA reached 8.61 times.

The last-twelve-month return on equity and return on assets reached -20.3% and -8.2%, respectively, due to the losses reported over the last fourth quarters, particularly the fourth quarter of 2022 due to the impairments accounted for in such period.

CONFERENCE CALL 1Q23

ENGIE Energía Chile is pleased to inform you that it will conduct a conference call to review its results for the quarter ended March 31, 2023, on Tuesday May 9, 2023
at 12:30 p.m. (EST) – 12:30 p.m. (Chile)

hosted by:
Eduardo Milligan, CFO ENGIE Energía Chile S.A.

To participate, please dial:
+1(412) 317-6378, international or
+**56 44 208 1274** Chile or
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To join the conference, please state the name of the conference (**ENGIE ENERGIA)**; no other Conference ID will be requested.
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To access the phone replay, which will be available until May 19, 2023, please dial
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