January 26, 2022

ENGIE ENERGÍA CHILE REPORTED EBITDA OF US$315 MILLION AND NET INCOME OF US$47 MILLION IN 2021.

EBITDA AMOUNTED TO US$71 MILLION IN THE FOURTH QUARTER OF 2021, A 39% DECREASE COMPARED TO THE FOURTH QUARTER OF 2020. THE EBITDA DROP IS PRIMARILY EXPLAINED BY THE INCREASE IN BOTH GENERATION COSTS AND SPOT PRICES, WHICH HAVE BEEN IMPACTED BY THE SEVERE DROUGHT IN THE COUNTRY AND THE STEEP RISE IN FUEL PRICES WORLDWIDE.

- **Operating revenues** amounted to US$1,479 million in 2021, a 9% increase compared to 2020, mainly due to the demand recovery in the regulated and unregulated segments and the increase in average realized energy prices explained by higher CPI and fuel prices.
- **EBITDA** amounted to US$315 million in 2021, a 31% decrease compared to 2020, mainly due to an increase in average energy supply costs and higher spot prices. This was due to weak hydro conditions, lower gas availability, generally lower performance of coal plants in the system, and rising coal and gas prices.
- **Net Income** reached US$47 million in 2021, a 71% decrease compared to 2020. This was basically due to the decrease in operating results and one-time financial expenses related to the sale of accounts receivable born from the application of the temporary price stabilization mechanism to regulated clients pursuant to Law #21,185 dated November 2019 ("PEC").

Financial Highlights (in US$ millions)

	4Q20	4Q21	Var %	12M20	12M21	Var%
Total operating revenues	**355.7**	**392.1**	***10%***	**1,351.7**	**1,478.6**	***9%***
Operating income	72.0	19.7	*-73%*	275.4	128.7	*-53%*
EBITDA	**117.5**	**71.3**	***-39%***	**455.3**	**314.5**	***-31%***
EBITDA margin	33.0%	18.2%	*(14,8pp)*	33.7%	21.3%	*(12,4pp)*
Total non-operating results	(24.1)	(5.8)	*n.a*	(71.7)	(67.9)	*-5%*
Net income after tax	40.3	8.7	*-78%*	163.5	47.4	*-71%*
Net income attributed to controlling shareholders	**40.3**	**8.7**	*-78%*	**163.5**	**47.4**	***-71%***
Earnings per share (US$/share)	0.054	0.008		0.155	0.045	
Total energy sales (GWh)	2,881	2,923	*1%*	11,408	11,715	*3%*
Total net generation (GWh)	1,133	1,493	*32%*	6,438	7,746	*20%*
Energy purchases on the spot market (GWh)	1,667	1,228	*-26%*	4,645	3,311	*-29%*
Energy purchases - back up (GWh)	127	265	*109%*	503	639	*27%*

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 December 31, 2021, 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.

Contents

HIGHLIGHTS:

COVID-19: The Corona virus, or COVID-19, was first detected in Chile on March 3, 2020, and as of January 25, 2022, 2,001,346 cases have been confirmed and 39,543 deaths have been reported. A constitutional state of catastrophe, was enacted on March 18, 2020, and was not lifted until September 30, 2021, given the progress in vaccination and reduction of contagion and mortality rates. In mid-January 2022, the government remains under alert given the growing number of the Omicron variant cases. The COVID-19 pandemic is deemed to be the worst sanitary and economic crisis in recent times. The COVID-19 pandemic has posed several challenges forcing us to adapt ourselves and to respond quickly along three lines of action: first, ensuring the safety and wellbeing of our teams; second, ensuring our company's operational continuity, which is essential for the continued electricity supply in our country; and, finally, coordinating ourselves as best as possible with our stakeholders including our customers, suppliers, shareholders and communities to keep an open, direct and collaborative dialogue. Since the beginning of this crisis, we established a crisis committee and have implemented contingency plans, adopting sanitary measures in our sites as necessary to comply with the authority's instructions. Similarly, we have monitored the situation and actions taken by our suppliers and contractors, asking them to comply with safety standards with their own staff. Beginning January 2022, the company adopted a hybrid approach, with a mix of in-person work at company facilities and home office, which is permanently adapted to the government's prevailing rules at any point in time. The government has implemented the *"Plan Paso a Paso"*, a step-by-step plan that considers five scenarios from a full lockdown to an advanced opening, each with specific restrictions and obligations. The advance or retrocession from one to another scenario is subject to epidemiologic indicators, sanitary network availability and traceability. Chile has implemented a widely recognized vaccination process, reporting over 16 million people vaccinated as of January 25,2022.

RECENT EVENTS

4Q21

- **Feller Rate national-scale rating:** On December 28, 2021, Feller Rate ratified ENGIE Energía Chile's AA- solvency rating and changed the outlook to Stable from Positive due to the challenges posed by the acceleration and correct execution of the company's investment plan to reconvert its asset generation base.

- **151 MW Calama wind farm:** The Calama wind farm, which began injecting energy to the SEN grid in July 2021, was officially declared under commercial operation by the system coordinator (CEN) on October 27, 2021. This project forms part of our ambitious transformation plan, which considers 2GW of renewable generation assets to achieve our zero-carbon goals. The Calama wind farm has 36 aerogenerators and total installed capacity of 151.2 MW.

- **Deferral of U14 and U15 disconnection:** The National Energy Commission (CNE), per Resolution #496 dated November 22, 2021, asked the company to postpone the disconnection of the coal-based units 14 and 15 in Tocopilla from the initially authorized date of December 31, 2021, to a date falling after June 30, 2022, for system security reasons. The CNE issued Resolution #496 in response to a request by the system Coordinator, who considered that, given the prolonged drought in the country and consequential reduction in hydraulic generation, the disconnection of Units 14 and 15, with aggregate gross capacity of 268 MW, could put the country's power supply at risk.

- **HVDC Kimal-Lo Aguirre transmission auction:** The right to develop, build and operate the HVDC, 1,500-kilometer long Kimal-Lo Aguirre transmission project was finally awarded to the Yallique Consortium formed by ISA Inversiones Chile SpA, Transelec Holdings Rentas Limitadas and China Southern Power Grid International (HK) Co. Limited. The Yallique consortium's proposal considers an annual tariff of US$116.3 million for this high-voltage direct current project running from the Antofagasta region in the north of Chile to the Santiago metropolitan region, with bipolar technology, dedicated metallic return, and 2 AC/DC converting substations. This project represents a strategic development to transport low-cost energy produced in the north of the country, and it is expected to be completed by 2028.

3Q21

- **Provisional dividend:** On July 27, 2021, the company's Board of Directors approved the distribution of a provisional dividend on account of 2021's net income in the amount of US$41.5 million, equivalent to US$0.0393996153 per share, which was paid to the company's shareholders on August 26, 2021.

- **IDB Invest financing:** On August 27, 2021, the company drew the US$125 million financing signed with IDB Invest on December 23, 2020, to finance the construction of the Calama wind farm. The loan structure seeks to accelerate the decarbonization of the company's energy matrix.

- **2021/01 power supply auction for regulated clients:** In September 2021, the National Energy Commission conducted a power supply auction for regulated clients, under which it awarded 2,310 GWh/yr at a record low average price of US$23.78/MWh, considered a milestone since the public auction scheme to ensure long-term power supply to distribution companies was enacted in 2005.

- **Transmission works auction:** On September 21, 2021, the Coordinator published the results of a transmission auction by which ENGIE was awarded the construction of the La Ligua substation, which will represent an estimated investment of US$19 million.

2Q21

- **Accounts receivable monetization**: On June 30, 2021, ENGIE Energía Chile sold to Chile Electricity PEC SpA the third group of accounts receivable from distribution companies born from the application of the electricity price stabilization mechanism enacted in November 2019. Eólica Monte Redondo completed the sale on July 5. Chile Electricity PEC raised the financing to buy receivables from four groups of generation companies through a US$419 million 4a2 delayed draw private placement with the participation of Allianz, IDB Invest and Goldman Sachs. During the second and third quarters of 2021, ENGIE and EMR sold accounts receivable with face value of US$28.8 million. They received US$20.8 million in cash proceeds and reported US$8 million in financial expenses.

- **Fitch rating confirmation**: On June 3, 2021, Fitch Ratings affirmed EECL's long-term foreign and local currency issuer default ratings at BBB+, and long-term national scale rating at AA(cl). Fitch also affirmed the company's US$850 million outstanding unsecured notes at BBB+ and its national equity rating at 'Primera Clase Nivel 2 (cl)'. The rating outlook is stable. EECL's ratings reflect the company's strong credit profile based on its improved capital structure, with expected leverage between 2.0x and 2.5x during 2021-2023, combined with a strong 100% contracted position until 2028 with a contracted average life of its PPAs of 11 years. The stable outlook is driven by Fitch's expectations that Engie will maintain adequate liquidity levels in the medium term, supported by strong and predictable cash flow.

- **Annual Ordinary Shareholders' Meeting**: On April 27, 2021, the Company's shareholders agreed the following:

    - **Definitive Dividends:** To pay a final dividend equivalent to US$51,055,643.26, or US$0,0484716314 per share, which together with the US$66.7 million provisional dividend paid on November 30, 2020, accounted for approximately 72% of 2020 net income. The final dividend was paid on May 20, 2021, in Chilean pesos at the dollar-equivalent observed rate published in the Official Gazette on May 17, to shareholders listed in the company's Shareholder Registry five business days before the dividend payment date.

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

    - **Local Rating Agencies:** To confirm "Feller Rate Clasificadora de Riesgo" and "Fitch Chile Clasificadora de Riesgo Ltda." as the agencies that will rate the company's shares according to the national rating scale.

1Q21

- **Price stabilization fund**: On March 11, 2020, the National Energy Commission ("CNE") published Exempt Resolution #72 setting the rules for the implementation of the temporary price stabilization mechanism for clients subject to regulated tariffs, as established in Law #21,185 dated November 2, 2019. This price stabilization mechanism froze electricity tariffs at the levels prevailing in the first half of 2019 until year-end 2027, subject to certain adjustments, from time to time, as provided by the law. At the same time, the tariffs charged by generation companies to distribution companies continue to follow the indexation formula set in the prevailing contracts among them. The mechanism has therefore produced a differential between the tariffs that generation companies are entitled to charge according to the terms of their contracts with distribution companies and the tariffs actually collected from regulated end-consumers. As a result of this price differential, generation companies have begun to build up an account receivable from distribution companies, which taken as a whole, gives birth to the so-called price stabilization fund. According to Law #21,185 this fund may increase until the first to occur between July 2023 or until it reaches a global amount of US$1,350 million. The authority expects that once lower-priced power supply agreements awarded in more recent auctions become effective, the average price of the contracts between generation and distribution companies will begin to decrease gradually starting 2021. At some point contract prices will fall below the stabilized price that will remain unchanged until December 31, 2027, subject to the adjustments defined by the law. When average contract tariffs fall below the stabilized price, distribution companies will begin repaying the accounts with generation companies that form part of the stabilization fund. As of December 31, 2021, EECL reported approximately US$90.4 million in accounts receivable related to the price stabilization mechanism, after selling accounts receivable with nominal total amount of US$167.3 million between February and July 2021, as explained below.

  - **Monetization of accounts receivable stemming from Tariff Stabilization Law**: On January 20, 2021, Engie Energía Chile S.A. ("EECL") and its subsidiary, Eólica Monte Redondo SpA ("EMR") reached an agreement with Goldman Sachs & Co. LLC and Goldman Sachs Lending Partners LLC ("GS") on the terms and conditions for a financing operation specifically related to current and future accounts receivable from distribution companies accrued in the context of Law #21,185, which creates an electricity tariff stabilization mechanism for regulated consumers, and exempt resolution #72 of the National Energy Commission ("CNE"), which set the rules for the application of the law. Under the financing transaction agreed with GS, EECL and EMR will be entitled to sell, without recourse to them, accounts receivable from distribution companies for up to a committed amount of US$162 million to Chile Electricity PEC SpA (the "Purchaser"). The sales of receivable will be perfected in groups, from time to time, as each Average Node Price decree ("PNP decree") is published including the corresponding chart with the balances owed by distribution companies to generation companies pursuant to the tariff stabilization law. On January 27, 2021, EECL, EMR and Inter-American Investment Corporation ("IDB Invest") reached an agreement under which IDB Invest will participate in the financing to the Purchaser for the acquisition of accounts receivable sold by EECL and EMR for up to a committed amount of US$74.7 million. The Company estimates that the total amount of accounts receivable, considering those already accrued and those to be accrued until the mechanism's cap is reached, which cannot occur after July 2023, could be approximately US$266 million. The sale of accounts receivable seeks to enhance the company's liquidity and procure the necessary financing resources in times of active investment in renewable generation projects.

  - On February 8, 2021, EECL and EMR sold the first group of accounts receivable to Chile Electricity PEC SpA. On March 31, EECL completed the sale of the second group of accounts receivable, while EMR sold its second group of accounts receivable on April 1. These sales were made under the terms and conditions agreed with Goldman Sachs and IDB Invest, as informed in material event notices published on January 20 and January 30, respectively. They comprised accounts receivable with total face value of US$141.9 million, representing approximately 54% of the total accounts receivable that ENGIE expects to accrue during the life of the price stabilization mechanism. The differential between the face value of the accounts receivable sold and the purchase price was accounted for as financial expenses in 2021 (US$40.9 million in the first quarter and US$0.9 million in April).

- **Chile rating downgrade by S&P Global Ratings**: S&P downgraded Chile's Long-Term Foreign-Currency Rating to 'A' from 'A+', changing the Outlook from Negative to Stable. The rating adjustment reflects a deterioration of the country's public finance, and the agency estimates that despite the economic recovery under way, the public debt will increase over the next years due to increased pressure on social expenditure.

- **Energy efficiency law**: On February 13, the government published the Energy Efficiency Law, which establishes that the Ministry of Energy will be required to present an energy efficiency plan every five years. The first plan will impose a 10% energy intensity reduction objective for the period 2019-2030.

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. Energy flows through the interconnection are variable, and until the full commissioning of the Interchile project, used to be predominantly in the south-north direction comprising inflows of renewable power generated in the area known as Norte Chico into the SING grid.

Following the commissioning of the last tranche of Interchile's Cardones-Polpaico transmission project on May 30, 2019, marginal costs in the different nodes of the SEN have reported greater coupling of transmission bars at different substations and the injection into the grid of renewable power generation, which was previously being lost due to insufficient transmission capacity.

Marginal Costs

2020	Minimun				Average				Maximum			
Month	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220
Jan	18.9	18.5	18.8	-	41.6	40.4	41.9	39.9	151.8	147.8	149.9	148.5
Feb	25.1	24.8	23.7	-	43.1	42.1	40.1	40.4	148.7	146.6	140.3	143.4
Mar	28.0	27.7	26.9	-	68.7	67.6	64.3	67.2	182.4	178.1	180.2	179.4
Abr	25.3	25.0	24.3	24.4	44.8	44.2	43.4	43.4	106.3	104.6	106.2	104.9
May	27.5	27.1	-	-	45.2	44.1	40.9	41.0	99.5	96.4	100.1	99.4
Jun	26.7	26.2	25.6	26.0	43.7	42.8	41.6	42.2	107.6	104.9	108.2	106.2
Jul	-	-	-	-	31.5	30.5	31.6	30.8	90.2	86.3	93.9	90.2
Aug	-	-	-	-	31.5	30.4	30.4	28.9	126.3	121.0	133.1	126.1
Sep	-	-	-	-	29.3	28.2	29.2	28.4	66.1	62.9	74.1	67.3
Oct	-	-	-	-	30.8	29.5	34.2	30.9	80.0	76.2	132.3	119.2
Nov	-	-	-	-	32.8	31.6	34.9	31.3	87.5	83.5	106.3	94.8
Dec	-	-	-	-	42.1	40.6	43.1	41.5	132.3	126.1	140.3	131.2

2021	Minimum				Average				Maximum			
Month	Crucero 220	Polpaico 220	Charrúa 220	Pto. Montt 220	Crucero 220	Polpaico 220	Charrúa 220	Pto. Montt 220	Crucero 220	Polpaico 220	Charrúa 220	Pto. Montt 220
Jan	-	0.2	0.2	0.2	50.8	58.9	57.1	86.9	145.6	157.3	153.2	172.4
Feb	-	-	-	34.7	75.9	84.5	83.2	151.3	169.6	169.6	165.5	206.2
Mar	17.3	21.6	26.3	35.3	75.6	84.2	87.4	165.5	173.0	178.1	177.7	232.7
Abr	0.4	0.5	0.4	0.5	71.3	78.3	82.7	130.2	170.2	179.8	179.6	191.4
May	0.2	0.2	0.2	9.0	77.1	81.5	81.6	108.8	198.3	184.7	181.7	209.2
Jun	9.0	10.5	10.3	7.5	67.2	67.8	65.9	62.6	195.7	192.6	187.2	188.7
Jul	-	19.8	19.8	21.1	105.3	122.3	128.9	126.2	197.4	206.9	207.8	216.6
Aug	-	-	-	-	99.4	113.8	127.7	130.4	314.3	305.3	302.0	324.7
Sep	-	-	-	-	47.1	55.9	56.6	67.5	175.6	192.4	185.9	208.9
Oct	-	-	-	-	48.7	49.7	48.6	145.4	219.8	211.7	203.3	240.0
Nov	-	-	-	-	67.8	70.4	70.3	207.3	275.1	241.5	235.6	288.1
Dec	-	-	-	-	84.5	89.1	86.6	212.0	225.5	217.8	212.9	267.4

Source: Coordinador Eléctrico Nacional

In the first quarter of 2021, marginal costs increased compared to previous quarters due to several factors: (i) lower reservoir levels which caused a reduction in hydraulic generation; (ii) the unavailability of cost-efficient coal plants due to both trips and maintenance outages postponed from 2020 as a result of the pandemic and (iii) lower gas availability explained by the total interruption of Argentine gas supply and delayed LNG shipments due to the Texas storms. Therefore, marginal costs at the Crucero node averaged US$67.4/MWh in the first quarter vs. US$48.7/MWh in the first quarter of 2020. The unavailability of some large, cost-efficient coal power plants in the first quarter led to the dispatch of higher-cost plants to meet the shortfall.

During the second quarter, marginal energy costs remained high, not only due to the continued low availability of hydro and efficient thermal plants, but also due to significant increases in international fuel prices and freight costs. In April, the average marginal cost at the Crucero node was US$71/MWh; that is, US$28/MWh higher than in April 2020, as higher-cost plants were dispatched to compensate for the lower production from hydroelectric plants and efficient thermal plants. Unavailable units during April included Guacolda 1,2&3, Angamos 1&2, and IEM. In May, the marginal cost at the Crucero node averaged US$77/MWh, climbing US$37/MWh over the average in May 2020, with unavailable units including Guacolda 3, CTH, Ventanas 2, Kelar, U15, and CTM 1,2&3. Finally, in June the marginal cost at Crucero averaged US$67/MWh, US$26/MWh above the June 2020 average, with unavailable units including Angamos 1, Guacolda 2, and CTH. The average marginal cost, or spot energy price, at the Crucero Node during the second quarter was US$71.9/MWh, compared to US$41.9/MWh in the second quarter of 2020.

In the third quarter, marginal energy costs remained high. The minimal hydro availability continued, although more abundant rainfall in August and September in Central Chile alleviated the pressure towards the end of the quarter. International coal and gas prices as well as freight costs, continued rising to unprecedented levels. In July, the average marginal cost at the Crucero node was US$105.3/MWh; that is, US$73.7/MWh higher than in July 2020, as higher-cost thermal plants were dispatched to compensate for the lower production from hydroelectric sources. Unavailable units during July included Guacolda, Angamos and Ventanas. In August, the marginal cost at the Crucero node averaged US$99.4/MWh, climbing by US$69/MWh over the August 2020 average, with unavailable units including IEM and CTM2. Finally, in September the marginal cost at Crucero dropped to US$47.1/MWh, still US$17.9/MWh above the September 2020 average, with unavailable units including Norgener, Nueva Renca, CTH and Guacolda). The average marginal cost, or spot energy price, at the Crucero Node during the third quarter was US$83.9/MWh, compared to just US$30.4/MWh in the third quarter of 2020.

At the beginning of the fourth quarter, marginal energy costs decreased due to the thaw, which temporarily relieved hydraulic generation. However, international coal and gas prices as well as freight costs, continued rising to record high levels in October, gradually decreasing thereafter. In October, the average marginal cost at the Crucero node was US$49/MWh; that is, US$14.5/MWh higher than in October 2020, although it remained stable as compared to September given the greater hydraulic generation (+146 MWavg.), the increase in solar generation and operation with Argentine gas (600 MWavg.). In November the marginal cost at the Crucero node averaged US$68/MWh, US$33/MWh above the November 2020 average due to lower availability of coal plants (~600 MW) and lower gas availability. On average, a US$6/MWh variable cost increase was reported by coal-based plants. Finally, in December, the marginal cost at Crucero averaged US$84.5/MWh; that is, US$41.4/MWh above the December 2020 average, due to the greater number of units undergoing maintenance (1,171 MW in the first half of the month and 616 MW in the second half) as well as forced outages of efficient thermal plants that had to be substituted by higher-cost units. Unavailable or limited units during the fourth quarter included Cochrane, Nueva Renca, Ventanas 2, Angamos, Guacolda, Santa María, Kelar, Nueva Ventanas, U16, CTA, CTH, CTM1 and IEM. The marginal cost at Crucero averaged US$67/MWh, compared to US$37.4/MWh in the fourth quarter of 2020.

Fuel prices

International Fuel Prices Index

	WTI (US$/Barrel)			Brent (US$/Barrel)			Henry Hub (US$/MMBtu)			European coal (API 2) (US$/Ton)		
	2020	2021	% Variation YoY	2020	2021	% Variation YoY	2019	2020	% Variation YoY	2019	2020	% Variation YoY
Jan	57.0	52.0	-9%	63.2	54.8	-13%	2.01	2.71	35%	50.4	67.8	35%
Feb	50.5	59.0	17%	55.7	62.3	12%	1.91	5.35	180%	48.3	65.9	36%
March	30.4	62.3	105%	33.5	65.3	95%	1.80	2.61	45%	47.9	68.4	43%
April	15.4	61.7	300%	18.1	64.9	258%	1.76	2.67	52%	45.0	71.8	60%
May	29.0	65.9	127%	30.0	68.9	130%	1.75	2.93	67%	38.6	86.1	123%
June	38.5	72.3	88%	41.1	74.1	80%	1.63	3.35	105%	45.6	108.4	138%
July	40.6	72.2	78%	43.3	75.0	73%	1.76	3.85	119%	49.9	132.8	166%
August	42.2	67.9	61%	44.5	71.0	60%	2.30	4.05	76%	49.0	148.8	204%
September	39.0	72.2	85%	40.3	75.0	86%	1.90	5.27	177%	52.3	173.0	231%
October	39.6	81.8	107%	40.3	83.7	108%	2.48	5.51	122%	56.4	206.3	266%
November	40.7	77.5	90%	44.8	79.8	78%	2.62	4.77	82%	53.8	159.4	196%
December	46.9	71.4	52%	50.4	74.8	48%	2.57	3.71	44%	66.2	121.1	83%

Source: Bloomberg, IEA

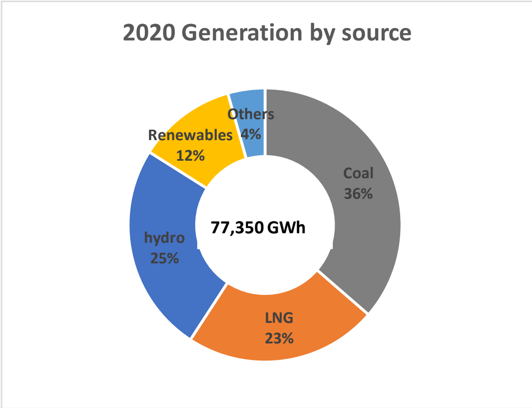
In 2021, fuel prices increased sharply, with average year-on-year rises of over 112%. In the case of coal, the price increase is primarily explained by the post-pandemic activity recovery, particularly in China. Moreover, China suffered an extreme heat wave and reported record electricity demand levels that led to power cuts. The heat waves also caused floods, which affected local coal production and transportation in China and Indonesia. In Europe, gas prices rose significantly given supply issues, while demand increased sharply as gas is viewed as the main fuel supporting the energy transition. The scarcity and extremely high prices of gas have led to the reactivation in coal generation.

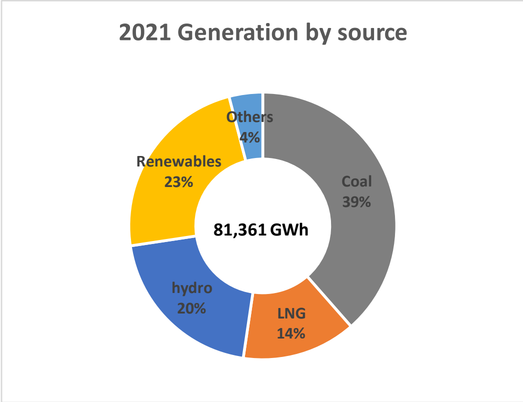
Coal supply has been unable to cope with the increase in demand and prices given the absence of players interested in investing in coal mines due to environmental concerns and lack of financing. Most coal mine expansions or reopenings have been halted, limiting any supply increases to the ability to raise production levels at existing mines.

In sum, both coal and gas inventories remain at critical levels, while demand is expected to grow during the upcoming winter months in the northern hemisphere. In the last quarter, the Chinese government took measures to release coal production and stabilize prices, which have finally reflected in a declining trend in coal future prices for the first months of 2022.

Generation

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





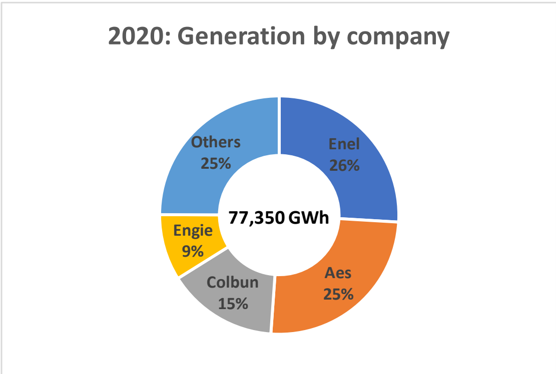
Source: Coordinador Eléctrico Nacional

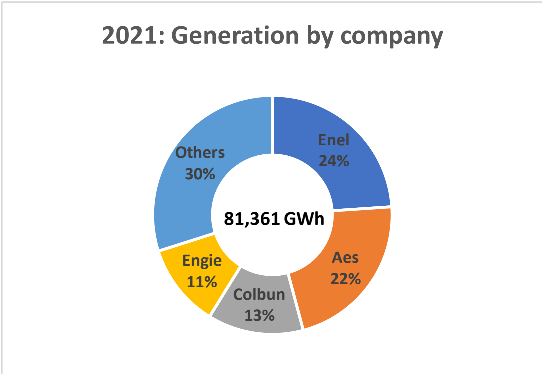
Peak demand reached 11,303 MWh/h in December 2021, representing a 2.6% increase compared to peak demand in 2020. Sales reached 74,878.7 GWh in 2021, with a 4.8% increase in free customer sales and a 4.3% increase in sales to regulated customers as compared to 2020.

Renewable energy production reached 22,146.7 GWh, with a 41% increase in solar generation and a 31% increase in wind generation as compared to 2020. During the fourth quarter of 2021 new renewable projects with combined gross capacity of 928.5 MW were added to the system.

During the fourth quarter of 2021, hydraulic generation dropped by 34%, as compared to the fourth quarter of 2020, and it dropped by 18% when compared to 2019. The levels at the Laja and Maule reservoirs are similar than those of 2020, while levels have increased at the Ralco and Chapo reservoirs due to a water saving decree. Rapel and Colbún have continued generating, but their water reserve levels have been preserved thanks to summer production restrictions. Rain and snowfall at the end of the third quarter of 2021 caused an improvement in reservoir tributary flows; however, these decayed quickly starting November.

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 audited consolidated financial statements for the 12-month periods ended December 31, 2021, and December 31, 2020. These financial statements have been prepared in U.S. dollars in accordance with IFRS. The information below should be read in conjunction with the financial statements and the notes thereto published by the Comisión para el Mercado Financiero (www.cmfchile.cl).

4Q 2021 compared to 3Q 2021 and 4Q 2020

Operating Revenues

Quarterly Information (In US$ millions)

	4Q 2020		3Q 2021		4Q 2021		% Variation	
Operating Revenues	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Unregulated customers sales……………………..	163.5	*54%*	161.3	*50%*	197.2	*55%*	*22%*	*21%*
Regulated customers sales…………………….	127.2	*42%*	160.3	*49%*	154.0	*43%*	*-4%*	*21%*
Spot market sales………………………………..	9.6	*3%*	3.6	*1%*	4.9	*1%*	*36%*	*-49%*
Total revenues from energy and capacity sales	**300.3**	*84%*	**325.2**	*89%*	**356.0**	*91%*	***9%***	***19%***
Gas sales…………………………..	13.4	*4%*	12.1	*3%*	9.4	*2%*	*-22%*	*-30%*
Other operating revenue……………………….	42.0	*12%*	28.5	*8%*	26.7	*7%*	*-6%*	*-36%*
Total operating revenues………………….	**355.7**	*100%*	**365.8**	*100%*	**392.1**	*100%*	***7%***	***10%***
Physical Data (in GWh)								
Sales of energy to unregulated customers (1)……	1,635	*57%*	1,662	*56%*	1,714	*59%*	*3%*	*5%*
Sales of energy regulated customers……	1,240	*43%*	1,303	*44%*	1,184	*41%*	*-9%*	*-4%*
Sales of energy to the spot market……………	5	*0%*	21	*1%*	25	*1%*	*n.a*	-
Total energy sales………………………….	**2,881**	*100%*	**2,986**	*100%*	**2,923**	*100%*	***-2%***	***1%***
Average monomic price unregulated customers(U.S.$/MWh)(2)	**99.6**		**98.0**		**113.4**		***16%***	***14%***
Average monomic price regulated customers (U.S.$/MWh)(3)	**102.6**		**123.0**		**130.0**		***6%***	***27%***

(1) Includes 100% of CTH sales.

(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$356 million in the fourth quarter of 2021, representing a US$38 million, or 19%, increase compared to the fourth quarter of 2020. This was mainly due to the recovery in physical sales to unregulated clients and higher average realized prices. The 21% increase in regulated customer sales was due to price increases, which offset lower volumes explained by the decrease in EECL's pro-rata in the pool of energy sales to distribution companies given the entrance of new supply contracts. The increase in CPI and fuel prices used in the regulated PPA tariff indexation formulas led to the increase in prices. Free client sales exhibited a 21% increase, despite the end of the Zaldívar PPA on June 30, 2020 (~37 GWh/month), due to demand recovery from the Codelco, Centinela and El Abra mines. The comparison with the third quarter of 2021 shows a recovery in physical sales to free clients and lower volume sales to regulated clients.

In the fourth quarter of 2021, sales to distribution companies in the center-south segment of the SEN reached 759 GWh, and decrease compared to 807 GWh reported in the fourth quarter of 2020 due to the incorporation of new PPAs from other suppliers into the pool of contracts with distribution companies, which caused a reduction in EECL's pro-rata share.

In the fourth quarter of 2021 the company's spot sales reached 25 GWh, an increase compared to 21 GWh reported in the third quarter, and 6 GWh reported in the fourth quarter of 2020.

In the fourth quarter of 2021, gas sales decreased compared to previous periods. 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. Beginning in the second quarter of 2020, this item includes income recognition corresponding to ENGIE's acquisition of a 40% interest in Inversiones Hornitos SpA through monthly installments according to the terms of the power supply agreement renegotiated with AMSA, which considers a tariff discount. In the fourth quarter of 2021, this item amounted to US$1.58 million compared to US$4.17 million in the third quarter, US$4.01 million in the second quarter and US$3.94 million in the first quarter.

Operating Costs

Quarterly Information (In US$ millions)

	4Q 2020		3Q 2021		4Q 2021		% Variation	
Operating Costs	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Fuel and lubricants………………………………	(48.9)	*17%*	(160.4)	*45%*	(117.6)	*32%*	*-27%*	*141%*
Energy and capacity purchases on the spot market……………………………	(90.7)	*32%*	(85.0)	*24%*	(125.2)	*34%*	*47%*	*38%*
Depreciation and amortization attributable to cost of goods sold…………………………….	(44.5)	*16%*	(43.6)	*12%*	(50.5)	*14%*	*16%*	*14%*
Other costs of goods sold…………………….	(89.9)	*32%*	(60.1)	*17%*	(62.9)	*17%*	*5%*	*-30%*
Total cost of goods sold………………..	**(274.0)**	*97%*	**(349.1)**	*98%*	**(356.2)**	*96%*	***2%***	***30%***
Selling, general and administrative expenses…	(8.0)	*3%*	(6.2)	*2%*	(9.1)	*2%*	*47%*	*15%*
Depreciation and amortization in selling, general and administrative expenses…………	(1.0)	*0%*	(1.0)	*0%*	(1.0)	*0%*	*10%*	*5%*
Other operating revenue/costs……………………….	(0.7)	*0%*	1.5	*0%*	(6.0)	*2%*		
Total operating costs….………………	**(283.7)**	*100%*	**(354.8)**	*100%*	**(372.4)**	*100%*	***5%***	***31%***
Physical Data (in GWh)								
Gross electricity generation								
Coal………………………………………….	792	*61%*	1,713	*70%*	1,084	*67%*	*-37%*	*37%*
Gas…………………………………………..	358	*28%*	678	*28%*	335	*21%*	*-51%*	*-6%*
Diesel Oil and Fuel Oil…………………….	5	*0%*	2	*0%*	0	*0%*	*-87%*	*-95%*
Hydro/Solar/Wind……………………………….	134	*10%*	52	*2%*	201	*12%*	*286%*	*51%*
Total gross generation…………………	**1,288**	*100%*	**2,444**	*100%*	**1,621**	*100%*	***-34%***	***26%***
Minus Own consumption………………..	(155)	*-12%*	(195)	*-8%*	(128)	*-8%*	*-34%*	*-17%*
Total net generation……………………	**1,133**	***39%***	**2,249**	***80%***	**1,493**	***50%***	***-34%***	***32%***
Energy purchases on the spot market………..	1,667	***57%***	434	***15%***	1,228	***41%***	*183%*	*-26%*
Energy purchases- bridge………..	127	***4%***	127	***5%***	265	***9%***	*n.a*	*n.a*
Total energy available for sale before transmission losses………………………	**2,927**	***100%***	**2,810**	***100%***	**2,986**	***100%***	***6%***	***2%***

Gross electricity generation increased by 26%, as compared to the same quarter of 2020, and by 34% when compared to the third quarter of 2021. The decrease in coal-based generation compared to the previous quarter was mainly due to lower availability of our coal plants and less frequent dispatch of other higher-cost units, such as U14-U15 and CTM, due to the greater hydraulic generation explained by the thaw season. During this quarter, CTM1, CTM2 and CTH were temporarily out of service due to planned maintenance. Gas generation decreased compared to both periods under analysis due to the major maintenance of the U16 CCGT. Renewable generation increased notably due to the commencement of operations of Parque Eólico Calama and the total energization of the Tamaya PV plant.

Through most of the fourth quarter, the electricity system in Chile remained stressed amid a relatively disappointing thaw season, with hydraulic resources quickly decreasing in the last two months of the year. The low hydro generation and high coal and gas prices resulted in high average operating costs in the system.

Despite the sharp increase in fuel prices in the fourth quarter of 2021, the fuel cost item decreased significantly compared to the third quarter due to the decrease in our own generation. The increase in the fuel cost item in the fourth quarter of 2021, as compared to the fourth quarter of 2020, is explained by the increase in our own generation and the sharp increase in international fuel prices.

The decrease in our own generation caused an increase in energy purchases on the spot market. Energy and capacity purchase costs increased by US$34.5 million (38%) compared to the fourth quarter of 2020, mainly due to higher average spot prices. The comparison with the third quarter of 2021 reveals a sharper increase in energy purchase volumes due to plant maintenance schedules; therefore, energy and capacity purchase costs rose by 47%. Part of our energy sales were supplied with contracted energy purchases from other generation companies in the system, which reached 265 GWh in the fourth quarter, up from 127 GWh in the third quarter, due to additional contracts signed to hedge our exposure to the spot market. Our energy purchases, either through contracts or through the spot market, are accounted for under the same item labelled 'Energy and capacity purchases on the spot market'.

The increase in depreciation costs is explained by the Calama wind farm and other major maintenance assets that began to be depreciated in the fourth quarter.

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

SG&A expenses were higher than those reported in the third quarter and in the fourth quarter of 2020 partly due to the depreciation of the Chilean peso and expenses related to IT and project development.

The Other operating revenue/cost item includes water sales and miscellaneous income as well as recoveries and provisions. EECL's share in TEN's net results is also included in this item. In the last quarter, we reported a US$6.1 million loss, which includes the probable impact of the retroactive application of estimated annual transmission revenues according to the new tariff decree, which is still in process. Although transmission tariffs have not yet been published and the company does not discard further legal actions in case of discrepancies with their calculation or the tariff setting process, the company has recognized estimated impacts on TEN's 2021 results as required by IFRS accounting norms.

Electricity Margin

Quarterly Information (In US$ millions)

	2020					2021				
	1Q20	**2Q20**	**3Q20**	**4Q20**	**2020**	**1Q21**	**2Q21**	**3Q21**	**4Q21**	**2021**
Electricity Margin										
Total revenues from energy and capacity sales………	**305.8**	**271.9**	**287.2**	**300.3**	**1,165.2**	**286.8**	**340.5**	**325.2**	**356.0**	**1,308.5**
Fuel and lubricants…………………..	(80.8)	(83.6)	(59.9)	(48.9)	(273.2)	(83.6)	(107.6)	(160.4)	(117.6)	(469.2)
Energy and capacity purchases on the spot market……	(93.2)	(69.2)	(71.7)	(90.7)	(324.8)	(104.7)	(90.0)	(85.0)	(125.2)	(404.9)
Gross Electricity Profit	**131.8**	**119.0**	**155.6**	**160.7**	**567.1**	**98.5**	**142.9**	**79.8**	**113.2**	**434.4**
Electricity Margin	*43%*	*44%*	*54%*	*54%*	*49%*	*34%*	*42%*	*25%*	*32%*	*33%*

In the fourth quarter of 2021, the electricity margin, or the gross profit from the electricity generation business, decreased by US$47.5 million, when compared to the fourth quarter of 2020, and represented 32% of energy and capacity revenues. On the one hand, we can observe a US$55.7 million revenue increase, explained by the demand recovery from the pandemic, and higher average realized monomic prices resulting from the increase in the PPA tariff indices (CPI and gas and coal prices). On the other, fuel costs increased by US$68.7 million due to an increase in international fuel prices. This was accompanied by a US$34.5 million increase in energy purchase costs due to an increase in both physical purchases and marginal costs in the electricity system. In sum, an increase in the average energy procurement cost, from US$49/MWh in the fourth quarter of 2020 to US$81/MWh in the fourth quarter of 2021, explains the reduction in the electricity margin.

Operating Results

Quarterly Information (in US$ millions)

EBITDA	**4Q 2021**		**3Q 2021**		**4Q 2021**		**% Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Total operating revenues………………………	355.7	*100%*	365.8	*100%*	392.1	*100%*	*7%*	*10%*
Total cost of goods sold……………………	(274.0)	*-77%*	(349.1)	*-95%*	(356.2)	*-91%*	*2%*	*30%*
Gross income…………………………	**81.7**	*23%*	**16.7**	*5%*	**35.9**	*9%*	***115%***	***-56%***
Total selling, general and administrative expenses and other operating income/(costs).	(9.7)	*-3%*	(5.7)	*-2%*	(16.2)	*-4%*	*185%*	*68%*
Operating income…………………….	**72.0**	*20%*	**11.0**	*3%*	**19.7**	*5%*	***79%***	***-73%***
Depreciation and amortization……...…………	45.5	*13%*	44.6	*12%*	51.6	*13%*	*16%*	*13%*
EBITDA…………………..……………….	**117.5**	*33.0%*	**55.6**	*15.2%*	**71.3**	*18.2%*	***28%***	***-39%***

Fourth-quarter EBITDA reached US$71.3 million, a US$46.2 million decrease compared to the same quarter of 2020. This was due to the drop in the electricity margin, in turn explained by the increase in average energy procurement costs. Operating revenues included a US$1.58 million income related to the acquisition of a 40% equity share in CTH, down from US$8.03 million reported in the fourth quarter of 2020. In December 2021, EBITDA was also hit by the recognition of a US$7 million loss corresponding to the potential retroactive impact of the new tariff decree on TEN. The tariff decree is still in process, but its potential impact was recognized in 2021 as required by IFRS norms.

Despite the recognition of the TEN loss, EBITDA increased by US$15.7 million in comparison with the third quarter, mainly due to the recovery in the electricity margin.

Financial Results

Quarterly Information (In US$ millions)

	4Q 2020		**3Q 2021**		**4Q 2021**		**% Variation**	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Financial income………..………………………	(0.6)	*0%*	0.4	*0%*	0.3	*0%*	*-21%*	*-163%*
Financial expense…………..…………………	(9.9)	*-3%*	(8.9)	*-3%*	(10.9)	*-3%*	*22%*	*10%*
Foreign exchange translation, net……………	(4.4)	*-1%*	8.0	*2%*	11.1	*3%*		*-354%*
Other non-operating income/(expense) net…	(9.3)	*-3%*	(0.2)	*0%*	(6.3)	*-2%*		*-32%*
Total non-operating results…………….	**(24.1)**	*-7%*	**(0.7)**	*0%*	**(5.8)**	*-2%*		
Income before tax……………………. ………	47.9	*14%*	10.3	*3%*	13.9	*4%*	***35%***	***-71%***
Income tax……………………………………	(7.6)	*-2%*	(1.6)	*0%*	(5.2)	*-2%*	*221%*	*-33%*
Net income from continuing operations after taxes …	40.3	*12%*	8.7	*3%*	8.7	*3%*	*1%*	*-78%*
Net income to EECL's shareholders	**40.3**	*12%*	**8.7**	*3%*	**8.7**	*3%*	***1%***	***-78%***
Earnings per share…………………….	**0.038**		**0.0**		**0.008**			

The increase in interest expense in the fourth quarter of 2021, as compared to the third quarter of 2021, is mainly explained by two factors: lower capitalization of interest in our projects under construction (US$2.4 million in 4Q21 vs. US$3.4 million in 3Q21) and interest expense on the US$125 million IDB Invest loan taken in August 2021. The latter also explains the US$1 million interest expense increase in 4Q21 compared to 4Q20. The most significant recurring interest expense item is made up of interest on our 144-A bonds, which reached US$8.9 million in each of the analyzed quarters.

Foreign-exchange profits reached US$11,1 million in the fourth quarter of 2021, up from an US$8 million profit in the third quarter of 2021 and a US$4.4 million loss in the fourth quarter of 2020. This was explained by the effects of a marked depreciation of the Chilean peso in the second half of 2021 over local currency liabilities related to IFRS 16 financial leases. These increased significantly due to onerous concessions on land for the future development of renewable projects. Foreign exchange variations affect the valuation of certain assets, liabilities and cash flows denominated in currencies other than the US dollar --the company's functional currency--, such as accounts receivable and payable, advances to suppliers, and value-added tax credit.

Net Earnings

The applicable income tax rate for both 2020 and 2021 is 27%.

In the fourth quarter of 2021, the company reported net income of US$8.7 million, an even result compared to the third quarter, but a marked decrease compared to the fourth quarter of 2020, due to the sharp increase in both fuel costs and system marginal costs that led to a reduction in EBITDA. The US$7 million adjustment on the investment in TEN booked in December to reflect the potential impact of the new tariff decree, which has not yet been published, also affected fourth-quarter net results.

2021 compared to 2020

Operating Revenues

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

	12M20		12M21		Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	%
Unregulated customers sales…………………..	612.9	*53%*	673.6	*51%*	*60.7*	*10%*
Regulated customers sales…………………….	528.2	*45%*	614.3	*47%*	*86.1*	*16%*
Spot market sales………………………………..	24.1	*2%*	20.6	*2%*	*-3.5*	*-14%*
Total revenues from energy and capacity sales……	**1,165.2**	*86%*	**1,308.5**	*88%*	***143.3***	*12%*
Gas sales…………………………..	37.9	*3%*	37.8	*3%*	*-0.1*	*0%*
Other operating revenue……………………….	148.6	*11%*	132.3	*9%*	*-16.3*	*-11%*
Total operating revenues………………….	**1,351.7**	*100%*	**1,478.6**	*100%*	***127.0***	*9%*
Physical Data (in GWh)						
Sales of energy to unregulated customers (1)……	6,463	*57%*	6,675	*57%*	*212*	*3%*
Sales of energy regulated customers……	4,931	*43%*	4,946	*42%*	*15*	*0%*
Sales of energy to the spot market…………….	15	*0%*	94	*1%*	*79*	*530%*
Total energy sales………………………….	**11,408**	*100%*	**11,715**	*100%*	***306***	*3%*
Average monomic price unregulated customers(U.S.$/MWh)(2)	**98.3**		**102.6**		***4.2***	*4%*
Average monomic price regulated customers (U.S.$/MWh)(3)	**107.1**		**124.2**		***17.1***	*16%*

(1) Includes 100% of CTH sales.

(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$952.5 million in the first nine months of 2021, representing a 10% or an US$87.6 million increase compared to the first nine months of 2020. The revenue increase was primarily explained by post pandemic demand recovery and an increase in average monomic prices resulting from the rise in tariff indexes (CPI, gas and coal prices). Tariff renegotiations, which in the case of the Centinela PPA included a larger discount in 2020 than in 2021 through which EECL is paying for the acquisition of a 40% interest in Inversiones Hornitos, also contributed to the revenue increase.

Physical energy sales to unregulated clients decreased mainly due to the end of the Zaldívar PPA in June 2020, although this effect was almost entirely offset by demand growth from other mining clients. Physical sales to regulated clients recovered due to looser COVID-driven restrictions on activity.

Physical sales to the spot market increased, but they remained low due to EECL's heavily contracted position. The spot market sales and purchase items also include the retroactive annual firm capacity price and monthly energy adjustment payments per the re-liquidations made by the grid coordinator.

Gas sales increased as compared to the first nine months of 2020, while the Other operating revenue account remained stable. Normally, this account includes transmission tolls and regulatory transmission revenues. However, it included included special items in both periods. In the first nine months of 2021, Other operating revenue included a US$5.3 million insurance compensation for a past loss at our IEM plant and US$3.6 million income from the sale of offices at the Apoquindo building. It also included a US$12.12 million financial income associated to the acquisition of 40% of Inversiones Hornitos SpA, which is being paid monthly through the tariff discount in the Centinela PPA. In 2020, the financial income related to the purchase of Inversiones Hornitos amounted to US$31.7 million.

Operating Costs

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

	12M 2020		12M 2021		Variation	
Operating Costs	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Fuel and lubricants……………………………	(273,2)	*25%*	(469,2)	*35%*	*195,9*	*72%*
Energy and capacity purchases on the spot market…	(324,8)	*30%*	(404,9)	*30%*	*80,1*	*25%*
Depreciation and amortization attributable to cost of goods sold…	(175,5)	*16%*	(181,9)	*13%*	*6,4*	*4%*
Other costs of goods sold……………………	(270,1)	*25%*	(255,6)	*19%*	*-14,6*	*-5%*
Total cost of goods sold………………..	**(1.043,7)**	*97%*	**(1.311,6)**	*97%*	***267,9***	***26%***
Selling, general and administrative expenses…	(32,6)	*3%*	(34,1)	*3%*	*1,5*	*5%*
Depreciation and amortization in selling, general and administrative expenses…	(4,4)	*0%*	(3,9)	*0%*	*-0,6*	*-13%*
Other operating revenue/costs……………………….	4,5	*0%*	(0,4)	*0%*	*4,8*	*-108%*
Total operating costs….………………..	**(1.076,3)**	*100%*	**(1.349,9)**	*100%*	***273,6***	***25%***
Physical Data (in GWh)						
Gross electricity generation						
Coal…………………………………………	4.419	*64%*	5.709	*68%*	*1.290*	*29%*
Gas…………………………………………..	2.176	*31%*	2.274	*27%*	*98*	*5%*
Diesel Oil and Fuel Oil…………………….	23	*0%*	23	*0%*	*0*	*-2%*
Hydro/Solar……………………………………….	327	*5%*	389	*5%*	*62*	*19%*
Total gross generation………………….	**6.945**	*100%*	**8.394**	*100%*	***1.450***	***21%***
Minus Own consumption………………..	(507)	*-7%*	(648)	*-8%*	*-141*	*28%*
Total net generation……………………	**6.438**	***56%***	**7.746**	***66%***	***1.308***	***20%***
Energy purchases on the spot market………..	4.645	***40%***	3.311	***28%***	*-1.333*	*-29%*
Energy purchases- bridge………..	503	***4%***	639	***5%***	*135*	*27%*
Total energy available for sale before transmission losses……………………..	**11.586**	***100%***	**11.696**	***100%***	***110***	***1%***

Gross electricity generation increased 21% in 2021. The generation mix revealed increases not only in coal generation, but also in gas generation as well as in renewable generation due to the acquisition of Eólica Monte Redondo in July 2020, and the contribution of the Calama wind farm, which began commercial, and the Tamaya PV plant, which was fully energized in the last quarter of the year.

The increase in generation and in international fuel prices led to a 72%, or US$195.9 million, increase in the fuel cost item in 2021.

Although physical electricity purchases dropped by 29%, the electricity purchase costs item rose by US$80.1 million (25%) because of higher spot prices. In 2021, the Chilean electricity system reported considerable stress due to a severe and prolonged drought, which led to shortages in hydraulic generation, and coincided with gas supply restrictions, technical issues with the coal generation fleet, and rising international fuel prices. These effects were partially mitigated by the expansion in solar and wind generation. To cover part of its energy sales commitments, the company has signed back-up PPAs with other generation companies, which in 2021 reached 639 GWh, a 27% increase compared to 2020.

Depreciation costs increased 4% due to the Calama wind farm and assets related to major maintenance, which began to be depreciated in 2021.

Other direct operating costs included, among others, transmission tolls, operating and maintenance costs, cost of fuel sold, and insurance premiums. This item, as a whole, increased due to higher maintenance costs. In addition, this item includes a US$11.9 million premium paid on the cancellation of an LNG shipment at the beginning of the year.

SG&A expenses increased slightly in part due to foreign-exchange effects.

The 'Other operating revenue/cost' item includes water sales, services and office rentals as well as the proportional result in TEN, which in 2021 was a US$1.9 million loss due to the recognition of a US$7 million accounting adjustment in December for the potential retroactive impact of the new tariff decree, which is still in process. In 2020, the proportional net income from TEN amounted to US$4.4 million.

Operating Results

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

EBITDA	**12M 2020**		**12M 2021**		**Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Total operating revenues………………………	1,351.7	*100%*	1,478.6	*100%*	*127.0*	*9%*
Total cost of goods sold……………………	(1,043.7)	*77%*	(1,311.6)	*89%*	*267.9*	*26%*
Gross income…………………………	**308.0**	*23%*	**167.0**	*11%*	***-140.9***	***-46%***
Total selling, general and administrative expenses and other operating income/(costs).	(32.6)	*2%*	(38.3)	*3%*	*5.7*	*18%*
Operating income…………………	**275.4**	*20%*	**128.7**	*9%*	***-146.7***	***-53%***
Depreciation and amortization……...…………	179.9	*13%*	185.8	*13%*	*5.9*	*3%*
EBITDA……………….………………	**455.3**	*33.7%*	**314.5**	*21.3%*	***-140.8***	***-31%***

In 2021, EBITDA reached US$314.5 million, a 31%, or US$140.8 million, decrease compared to 2020, mainly due to higher energy procurement costs explained by higher fuel prices and higher average spot energy purchase costs. The accounting adjustment in TEN explains US$7 million of the EBITDA decrease.

Financial Results

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

	12M 2020		12M 2021		Variation	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Financial income……….………………………	2.5	*0%*	1.6	*0%*	*-0.9*	*-37%*
Financial expense…………..…………………	(59.5)	*-5%*	(88.8)	*-9%*	*-29.3*	*49%*
Foreign exchange translation, net……………	(7.3)	*-1%*	22.6	*2%*	*29.9*	*-411%*
Other non-operating income/(expense) net…	(7.5)	*-1%*	(3.3)	*0%*	*4.2*	*-56%*
Total non-operating results……………	**(71.7)**	*-6%*	**(67.9)**	*-7%*		
Income before tax……………………. ………	203.7	*18%*	60.8	*6%*	***-142.9***	***-70%***
Income tax………………………………………	(40.2)	*-4%*	(13.4)	*-1%*	*26.8*	
Net income from continuing operations after taxes	163.5	*15%*	47.4	*5%*	*-116.2*	*-71%*
Net income to EECL's shareholders	**163.5**	*15%*	**47.4**	*5%*	***-116.2***	***-71%***
Earnings per share……………………..	**0.155**		**0.045**	*0%*		

The decrease in financial income is explained by lower interest rates and lower average cash balances.

The increase in interest expense in 2021 is explained by the discount on the sale of long-term accounts receivable from distribution companies related to the tariff stabilization law. The difference between the face value of the accounts receivable sold and the amount received, which includes the financial discount as well as transaction expenses, was reported as financial expenses. In 2021, EECL and its subsidiary EMR, sold accounts receivable with total face value of US$167.3 million and received US$118.6 million in cash proceeds, representing a financial expense of US$48.7 million.

In 2020, interest expense included the premium and make-whole paid to bondholders of the US$400 million 144-A bond with original maturity in January 2021. EECL carried out a liability management transaction by which it refinanced the existing bond with the proceeds of a new 10-year bond issue, which was successfully placed on January 23, 2020, in an amount of US$500 million at a 3.4% annual coupon rate. In February 2020, EECL completed the full repayment of the US$400 million bond and the premium payments in an amount of US$13.6 million, fully charged against 2020 results.

Capitalized interest amounted to US$10.1 million in 2021, up from US$4.4 million in 2020.

Foreign-exchange income amounted to US$22.6 million, which compares to a US$7.3 million loss in 2020, mainly due to the effect of the depreciation of the Chilean peso on financial leases accounted for under IFRS 16 related to onerous concessions on land signed with the *Ministerio de Bienes Nacionales.*

Net Earnings

The applicable income tax rate for both periods is 27%.

In 2021, net income after taxes reached US$47.4 million, down from US$163.5 million in 2020. As explained earlier, the decrease is primarily explained by the lower operating results and the one-shot US$48.7 million financial cost on the sale of accounts receivable from distribution companies related to the price stabilization law.

Liquidity and Capital Resources

As of December 31, 2021, EECL reported consolidated cash balances of US$215 million, while its nominal financial debt[1] amounted to US$1,025 million, with no scheduled debt principal payments until January 2025, except for a US$50 million short-term loan from Scotiabank maturing in April 2022.

For the 12-month period ended december 30 (in US$ millions)

Cash Flow	**2020**	**2021**
Net cash flows provided by operating activities…	231.3	132.0
Net cash flows used in investing activities………	(241.5)	(202.7)
Net cash flows provided by financing activities..	2.9	52.0
Change in cash………………...………….	**(7.3)**	**(18.8)**

Cash Flow from Operating Activities

In 2021, the company reported net operating cash flows of US$132 million, as reported in our cash flow statement. Cash inflows included US$65.9 million of cash from operations plus US$118.7 million in cash proceeds from the sale of accounts receivable from distribution companies to Chile Electricity PEC SpA. Cash outflows included US$27.2 million in interest expense (US$37.3 million cash payments minus US$10.1 million capitalized interest included as capital expenditures), and income tax payments of US$25.3. We note that on the last business day of 2021, we received a US$29.9 million duplicated payment from a customer, which we could not reimburse until the first business day of 2022. For purposes of this analysis, we have deducted this amount from the US$65.9 million operating cash flow figure, arriving at a net operating cash inflow of US$36 million in 2021, well below the operating cash flow reported in 2020 due mainly to sharp increases in fuel prices and marginal energy costs.

In 2020, cash flow generated from operating activities reached US$231.3 million after deducting income and green taxes (US$78.3 million) and interest payments (US$55.7 million), which in turn include the US$13.6 million loss related to premiums paid on the early redemption of the US$400 million 144A bonds with original maturity in January 2021. Cash from operating activities before interest and taxes reached US$365.3 million.

Cash Flow Used in Investing Activities

In 2021, net cash outflows from investing activities amounted to US$203 million, mainly due to (i) capital expenditures (US$208.6 million) and (ii) an US$8 million cash inflow corresponding to debt repayments from the related company, TEN, in January 2021. Capital expenditures included our investment in the Calama windfarm and in the solar PV projects, Tamaya, Capricornio and Coya, as well as investments in plant maintenance and transmission assets.

This figure is below the US$241.5 million invested in 2020, which included capital expenditures of US$185 million and US$53 million invested in the Eólica Monte Redondo acquisition.

(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.

Capital Expenditures

Our capital expenditures in 2020 and 2021 amounted to US$185.1 million and US$208.6 million, respectively, as shown in the following table. These amounts include VAT payments and capitalized interest. The latter amounted to US$4.4 million in 2020 and US$10.1 million in 2021.

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

CAPEX	**2020**	**2021**
Substation…………………	15.3	8.3
Overhaul power plants & equipment maintenance and refurbishing…………………	9.8	13.1
Overhaul equipment & transmission lines	5.1	6.6
PV Power Plant……………	88.5	105.4
Wind farm……………..	61.0	65.2
Others……………………………………………	5.4	10.0
Total capital expenditures………………………	**185.1**	**208.6**

Cash Flow from Financing Activities

In 2021, the main financing cash flows included (i) US$91.2 million in dividend payments (US$49.7 million final dividend on account of 2020 net results and US$41.5 million provisional dividend on account of 2021 results); (ii) the disbursement of the US$125 million IDB Invest loan; (iii) a US$24 million cash equity contribution into Inversiones Hornitos by the former minority shareholder; and (iv) the payment of US$6.5 million in financial lease installments. Interest paid on the two 144-A bonds (US$32.75 million), as well as on the US$50 million short-term debt (US$0.8 million), are reported in the operating cash flow section. Likewise, the proceeds of the sale of accounts receivable from distribution companies for a total amount of US$118.6 million, were reflected in the operating cash flow section. The company refinanced the Banco Estado US$50 million loan with a 1-year loan from Scotiabank for the same amount.

In 2020, the company reported financing activity related to a 144A/RegS issue in an amount of US$500 million. The proceeds of the issue were used to fully prepay the US$400 million 144A/RegS bond with original maturity in January 2021 including accrued interest, financial costs, stamp taxes and premiums on early redemption of the bonds. The company also prepaid two short-term loans with Scotiabank and Banco Estado for an aggregate amount of US$80 million, and in May 2020 took a new, 1-year, US$50 million loan with Banco Estado. Finally, in December 2020, the company paid a US$66.6 million interim dividend on account of 2020 net income.

Contractual Obligations

The following table sets forth the maturity profile of our debt obligations as of December 30, 2021.

Contractual Obligations as of 12/31/21
Payments Due by Period (in US$ millions)

	Total	< 1 year	1 - 3 years	3 - 5 years	More than 5 years
Bank debt……………………………………….……	**175.0**	50.0	-	7.7	117.3
Bonds (144 A/Reg S Notes)……………………..	**850.0**	-	-	350.0	500.0
Obligation w/customer…………………...……	**29.9**	29.9	-	-	-
Financial lease - Tolling Agreement TEN………	**54.9**	1.5	3.5	4.3	45.6
Financial lease - IFRS 16………………………….	**147.3**	6.3	8.8	12.3	119.9
Deferred financing cost…………………………..	**(17.0)**	-	(6.2)	(5.2)	(5.6)
Accrued interest…………………………………..	**14.3**	14.3	-	-	-
Mark-to-market swaps……………………………	**5.5**	5.5	-	-	-
Total	**1,260.0**	**107.6**	**6.1**	**369.0**	**777.3**

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 December 31, 2021, the company's short-term debt included a US$50 million loan with Scotiabank maturing on April 26, 2022. This loan is denominated in US dollars, accrues a fixed interest rate and is 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.

EECL has 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.

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, has the purpose of financing 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 generation 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.

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$54.9 million and is payable in monthly instalments totaling approximately US$7 million per year until 2037.

As of December 31, 2021, the company reported leasing obligations in respect to land use concessions, vehicles and other assets for a total amount of US$147.3 million, which qualified as financial debt under the IFRS 16 accounting norm.

Finally, as discussed above, the company received a US$30 million duplicated payment from a customer on the last business day of the year. The amount was accounted for as financial debt and funds were returned at the beginning of 2022.

Dividend Policy

Our dividend policy, last approved at the Annual Ordinary Shareholders' Meeting dated April 27, 2021, 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.

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

On October 27, 2020, the company's Board approved the payment of a US$66.6 million provisional dividend on account of 2020's net earnings. On November 30, shareholders were paid US$0.0632310625 per share, in its Chilean-peso equivalent using the peso-dollar observed rate published by the Official Gazette on November 23, 2020.

On April 27, 2021, at the Annual Ordinary Shareholders Meeting, our shareholders approved the Board's proposal to pay a final dividend of US$51,055,643.26 (US$0.0484716314 per share) on account of 2020's net income, payable on May 20, 2021, to those shareholders listed in the Shareholder Registry five business days prior to the payment date.

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.

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

In the normal course of business, EECL is exposed to several risk factors that may impact its operating and financial performance.

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 the construction of a risk matrix called Enterprise Risk Management, which is approved annually and is reviewed quarterly in each of the company's functional committees where risk mitigation action plans are defined and monitored. Management presents the company's risk management performance to the board on an annual basis.

Hedging Policy

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

Business Risk and Commodity Hedging

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. Another example refers to the tariff of our contract with distribution companies in the northern SEN, which became effective in 2012, and is readjusted semiannually according to the Henry Hub and the US CPI. There is a mismatch between the Henry Hub index used to define the contract tariff (four-month average prior to the tariff fixing, which takes place every six months) and the Henry Hub index prevailing at the time each LNG shipment is made. In the specific case of this contract, this risk is mitigated by an automatic tariff indexation triggered any time the price formula reports a fluctuation of 10% or more. Hence, we periodically define and execute financial hedging strategies to cover our residual exposure to international commodity price risks, including coal price indices, Brent and Henry Hub.

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 rates. 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. Even though 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. Per this law and resolution #72, by which the National Energy Commission set the terms of implementation of the law, accounts receivable from distribution companies will increase 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. 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 impacted the income statement in 2021. In 2021, the total nominal amount of notes sold by ENGIE and EMR was US$167.3 million, and the related financial expense reached US$48.7 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 and zero-cost collars. As of December 31, 2021, the Company reported forward FX contracts for a total nominal amount of US$102 million, with US$8.5 million maturing in each month of 2022.

In the past we and our subsidiary CTA have signed foreign-currency derivative contracts to hedge the UF and EUR cash flows stemming from EPC contracts, to avoid cash flow or investment value variations resulting from foreign currency fluctuations that are beyond management's control. As of December 31, 2021, there were no outstanding derivative contracts associated with such EPC contract cash flows.

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 December 31, 2021, 98.1% of our available cash and short-term investments were denominated in US dollars.

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 December 31, 2021, 89% of our financial debt was at fixed rates, while 11% (US$ 110 million under the IDB Invest financing) 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 December 31, 2021
Contractual maturity date (in US$ millions)

	Average interest rate	2021	2022	2023	2024	Thereafter	Grand Total
Variable Rate							
(US$)	2.295% p.a.	-	-	-	-	110.0	110.0
Fixed Rate							
(US$)	0.880% p.a.	50.0	-	-	-	-	50.0
(US$)	1.000% p.a.	-	-	-	-	15.0	15.0
(US$)	3.400% p.a.	-	-	-	-	500.0	500.0
(US$)	4.500% p.a.	-	-	-	-	350.0	350.0
Total Fixed Rate		**50.0**	**-**	**-**	**-**	**865.0**	**915.0**
TOTAL		**50.0**	**-**	**-**	**-**	**975.0**	**1,025.0**

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.

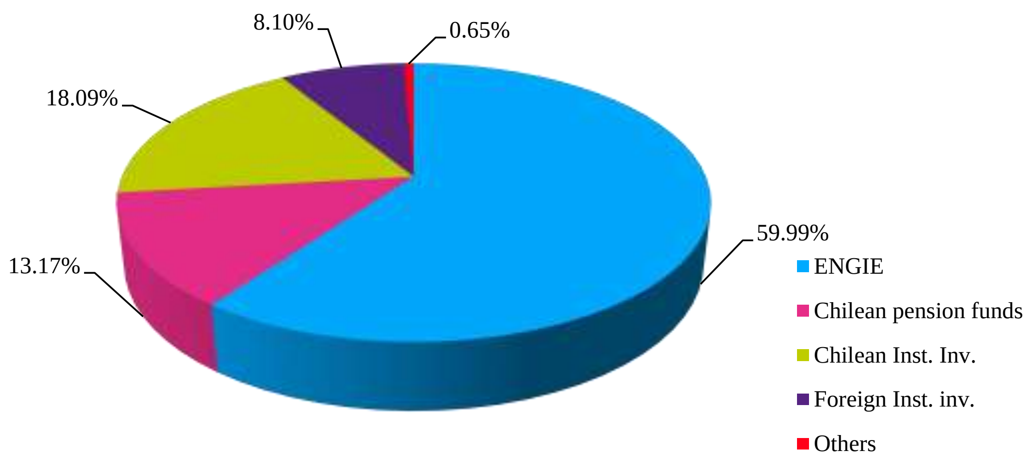
Over the last years, the electricity generation business and its customer base have evolved. Particularly, consumers with demand between 500 kW and 5 MW are allowed to contract their power supply directly with generation companies rather than through distribution companies. This disintermediation trend has 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 December 31, 2021, the contracts signed with smaller commercial and industrial clients represented a low percentage of our overall client portfolio.

The outbreak of the COVID-19 pandemic is leading to economic downturns, economic stimulus packages and inflation, with the consequential uncertainty about the behavior of power demand and the financial capacity of consumers of essential services to afford the timely payment of their bills. To face this situation the company has instructed its commercial areas to maintain close, direct contact with our customers to monitor the situation and take timely measures as necessary to both support our customers and mitigate the impact on the company's performance.

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 DECEMBER 31, 2021

Number of shareholders: 2,210



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

APPENDIX 1

PHYSICAL DATA AND SUMMARIZED QUARTERLY FINANCIAL STATEMENTS

Physical Sales

Physical Sales (in GWh)

	2020					2021					
	1Q20	**2Q20**	**3Q20**	**4Q20**	**12M20**	**1Q21**	**2Q21**	**3Q21**	**9M21**	**4M21**	**12M21**
Physical Sales											
Sales of energy to unregulated customers.	1,672	1,662	1,493	1,635	6,463	1,628	1,671	1,662	4,961	1,714	6,675
Sales of energy to regulated customers	1,285	1,122	1,283	1,240	4,931	1,197	1,262	1,303	3,762	1,184	4,946
Sales of energy to the spot market………	-	3	6	5	15	24	24	21	69	25	94
Total energy sales………………………….	**2,957**	**2,788**	**2,783**	**2,881**	**11,408**	**2,849**	**2,956**	**2,986**	**8,792**	**2,923**	**11,715**
Gross electricity generation											
Coal………………………………………….	1,304	1,276	1,046	792	4,419	1,280	1,633	1,713	4,625	1,084	5,709
Gas…………………………………………..	493	705	620	358	2,176	622	639	678	1,938	335	2,274
Diesel Oil and Fuel Oil…………………….	17	1	0	5	23	13	8	2	23	0	23
Renewable……………………………………….	46	35	112	134	327	62	74	52	187	201	389
Total gross generation………………….	**1,861**	**2,017**	**1,779**	**1,288**	**6,945**	**1,977**	**2,353**	**2,444.3**	**6,774**	**1,621**	**8,394**
Minus Own consumption………………..	(82)	(148)	(122)	(155)	(507)	(146)	(179)	(195)	(520)	(128)	(648)
Total net generation…………………….	**1,779**	**1,869**	**1,657**	**1,133**	**6,438**	**1,831**	**2,174**	**2,249**	**6,254**	**1,493**	**7,746**
Energy purchases on the spot market………..	1,063	821	1,093	1,667	4,645	932	717	434	2,083	1,228	3,311
Energy purchases- bridge	125	125	127	127	503	122	124	127	373	265	639
Total energy available for sale before transmission losses………………………	**2,967**	**2,815**	**2,877**	**2,927**	**11,586**	**2,885**	**3,015**	**2,810**	**8,710**	**2,986**	**11,696**

Quarterly Income Statement

Quarterly Income Statement (in US$ millions)

IFRS										
Operating Revenues	**1Q20**	**2Q20**	**3Q20**	**4Q20**	**12M20**	**1Q21**	**2Q21**	**3Q21**	**4Q21**	**12M21**
Regulated customers sales………………………	134.1	127.5	139.5	127.2	528.2	123.1	177.0	160.3	154.0	614.3
Unregulated customers sales…………………..	164.0	142.9	142.5	163.5	612.9	158.4	156.7	161.3	197.2	673.6
Spot market sales……………………………..	7.8	1.5	5.2	9.6	24.1	5.3	6.9	3.6	4.9	20.6
Total revenues from energy and capacity sales…………………	**305.8**	**271.9**	**287.2**	**300.3**	**1,165.2**	**286.8**	**340.5**	**325.2**	**356.0**	**1,308.5**
Gas sales…………………………..	5.9	7.6	10.9	13.4	37.9	7.7	8.7	12.1	9.4	37.8
Other operating revenue……………………….	23.5	42.6	40.6	42.0	148.6	37.8	39.3	28.5	26.7	132.3
Total operating revenues…………………	**335.3**	**322.0**	**338.7**	**355.7**	**1,351.7**	**332.3**	**388.5**	**365.8**	**392.1**	**1,478.6**
Operating Costs									-	-
Fuel and lubricants………………………………	(80.8)	(83.6)	(59.9)	(48.9)	(273.2)	(83.6)	(107.6)	(160.4)	(117.6)	(469.2)
Energy and capacity purchases on the spot	(93.2)	(69.2)	(71.7)	(90.7)	(324.8)	(104.7)	(90.0)	(85.0)	(125.2)	(404.9)
Depreciation and amortization attributable to cost of goods sold..	(41.2)	(41.7)	(48.1)	(44.5)	(175.5)	(44.4)	(43.4)	(43.6)	(50.5)	(181.9)
Other costs of goods sold…………………….	(52.9)	(62.5)	(64.8)	(89.9)	(270.1)	(71.4)	(61.2)	(60.1)	(62.9)	(255.6)
Total cost of goods sold………………..	**(268.1)**	**(257.0)**	**(244.5)**	**(274.0)**	**(1,043.7)**	**(304.1)**	**(302.1)**	**(349.1)**	**(356.2)**	**(1,311.6)**
Selling, general and administrative expenses…	(7.7)	(8.7)	(8.3)	(8.0)	(32.6)	(9.1)	(9.6)	(6.2)	(9.1)	(34.1)
Depreciation and amortization in selling, general and administrative expenses…	(1.1)	(1.5)	(0.8)	(1.0)	(4.4)	(0.8)	(1.0)	(1.0)	(1.0)	(3.9)
Other revenues………..…………………….	(1.6)	4.9	1.9	(0.7)	4.5	2.6	1.6	1.5	(6.0)	(0.4)
Total operating costs….………………	**(278.5)**	**(262.3)**	**(251.8)**	**(283.7)**	**(1,076.3)**	**(311.5)**	**(311.2)**	**(354.8)**	**(372.4)**	**(1,349.9)**
Operating income….………………	**56.8**	**59.7**	**86.8**	**72.0**	**275.4**	**20.7**	**77.3**	**11.0**	**19.7**	**128.7**
EBITDA……………….…………………	**99.1**	**103.0**	**135.8**	**117.5**	**455.3**	**65.9**	**121.7**	**55.6**	**71.3**	**314.5**
Financial income………..………………………	1.6	1.0	0.5	(0.6)	2.5	0.6	0.3	0.4	0.3	1.6
Financial expense………….…………………	(28.5)	(10.6)	(10.5)	(9.9)	(59.5)	(52.2)	(16.8)	(8.9)	(10.9)	(88.8)
Foreign exchange translation, net……………	(0.4)	(0.9)	(1.7)	(4.4)	(7.3)	1.7	1.9	8.0	11.1	22.6
method	-	-	-	-	-	-	-	-	-	-
Other non-operating income/(expense) net………………………	1.7	0.2	(0.1)	(9.3)	(7.5)	3.6	(0.5)	(0.2)	(6.3)	(3.3)
Total non-operating results……………	**(25.6)**	**(10.4)**	**(11.7)**	**(24.1)**	**(71.7)**	**(46.3)**	**(15.1)**	**(0.7)**	**(5.8)**	**(67.9)**
Income before tax…………………..………	31.3	49.4	75.2	47.9	203.7	(25.5)	62.2	10.3	13.9	60.8
Income tax………………………………………	(5.6)	(8.8)	(18.1)	(7.6)	(40.2)	8.0	(14.6)	(1.6)	(5.2)	(13.4)
Net income from continuing operations after taxes …….	25.6	40.6	57.0	40.3	163.5	(17.6)	47.6	8.7	8.7	47.4
Net income attributed to controlling shareholders……………….	**25.6**	**40.6**	**57.0**	**40.3**	**163.5**	**(17.6)**	**47.6**	**8.7**	**8.7**	**47.4**
Net income attributed to minority shareholders……………….	-	-	-	-	-	-	-	-	-	-
Net income to EECL's shareholders…….	**25.6**	**40.6**	**57.0**	**40.3**	**163.5**	**(17.6)**	**47.6**	**8.7**	**8.7**	**47.4**
Earnings per share…………………….. (US$/share)	**0.024**	**0.039**	**0.054**	**0.038**	**0.155**	**(0.017)**	**0.045**	**0.008**	**0.008**	**0.045**

Quarterly Balance Sheet

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

	2020 December	2021 December
Current Assets		
Cash and cash equivalents	235.3	215.7
Accounts receivable	108.1	171.4
Recoverable taxes	29.9	23.9
Current inventories	76.7	158.3
Other non financial assets	14.9	46.9
Total current assets	**464.9**	**616.2**
Non-Current Assets		
Property, plant and equipment, net	2,668.9	2,746.1
Other non-current assets	587.2	636.5
TOTAL ASSETS	**3,721.0**	**3,998.9**
Current Liabilities		
Financial debt	68.6	106.2
Other current liabilities	254.9	291.3
Total current liabilities	**323.5**	**397.5**
Long-Term Liabilities		
Financial debt	964.3	1,152.4
Other long-term liabilities	265.2	277.0
Total long-term liabilities	**1,229.5**	**1,429.4**
Shareholders' equity	2,168.0	2,172.0
Equity	**2,168.0**	**2,172.0**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,721.0**	**3,998.9**

Main Balance Sheet Variations

The main balance-sheet variations between December 31, 2020, and December 31, 2021, are the following:

Cash and cash equivalent: The company's cash balances decreased by US$19.7 million to US$215 million mainly because of (i) capital expenditures (US$199 million), (ii) US$91 million in dividend payments, (iii) interest payments (US$37 million), and (v) income tax payments (US$25 million). These cash expenditures were offset by (i) net operating cash inflows (US$36 million), (ii) the proceeds of the sale of accounts receivable from distribution companies related to the price stabilization mechanism (US$118 million), (iii) a US$24 million cash equity injection from the former minority shareholder in Inversiones Hornitos, (iv) an US$8 million payment received from TEN, (v) and the disbursement of the IDB Invest loan for US$125 million.

Accounts receivable: The US$63.4 million increase comprises changes in two different accounts: On the one hand, accounts receivable from third parties reported a US$57.8 million increase mainly because of relevant invoices that were paid at the beginning of January 2022 and deferred payments agreed with some distribution companies in the context of the pandemic. On the other hand, intercompany receivables increased by US$5.6 million, mainly due to an invoice due from Engie Gas.

Current inventories: The US$81.6 million increase in this item is explained by an increase in coal (+US$76.7 million), LNG (+US$2.9 million) and lime and limestone (+US$2 million) inventories due to the increase in prices reported by these commodities and the increase in required stocks to face the system shortfall in hydraulic generation.

Recoverable taxes: The US$6.3 million decrease in this account as of December 31, 2021, is explained by lower monthly provisional tax payments and (-US$1.9 million) and lower recoverable taxes from previous periods (-US$4.6 million).

Other non-financial assets – current: The US$32 million increase in this item is explained by a US$26.6 million increase in the VAT fiscal credit balance due to increased capital expenditures in new projects and a US$4.0 million increase in advanced payments of insurance premiums.

Property, plant and equipment, net: The US$24.1 million increase in PP&E was explained by capital expenditures related to investments in renewable energy and transmission projects (US$208 million), which were offset by depreciation of US$166 million and asset sales and write-offs for an aggregate amount of US$13.4 million.

Other non-current assets: The US$56.6 million net increase in this item resulted primarily from (i) a US$34.6 million increase in the investment in TEN associated to the mark-to-market of derivatives; (ii) a US$91.7 million increase in rights of use of certain assets, mainly onerous concessions on land for the renewable projects (IFRS16); and (iii) a US$14.3 million increase in project development costs. These increases were partially offset by (i) a US$54.3 million decrease in long-term accounts receivable due to the sale of receivables associated to the enactment of the price stabilization law; (ii) the reduction in intercompany receivables due to an US$8 million payment from TEN; (iii) amortization of intangible assets (US$16.3 million); (iv) the transfer from other assets to fixed assets of US$4.6 million invested in the Coya project due to the start-up of the project's construction; and (v) a US$1.3 million decrease in deferred taxes.

Financial debt – current: This item reported a US$37.4 million short-lived increase mainly due to the duplicated payment of a US$29.8 million invoice on the last business day of the year, which had to be reported as financial debt until the return of the funds at the beginning of 2022. A US$5.5 million increase in the mark-to-market of derivatives to hedge our exposure to foreign-currency risks, as well as a US$2 million increase in the current portion of financial lease obligations, also contributed to the increase in short-term financial debt.

Other current liabilities: The US$36.5 million net increase in this item is explained by a US$56.4 million increase in accounts payable to suppliers, partially offset by (i) lower provisions for employee benefits and annual performance bonuses (US$4.6 million); (ii) a US$7.2 million decrease in VAT payables; (iii) a US$6.5 million decrease in income tax provisions due to lower results and application of instant depreciation, and (iv) a US$1.7 million decrease in intercompany payables.

Long-term financial debt: The US$188.1 million increase in this account is mainly explained by (i) the US$125 million loan from IDB Invest and (ii) a US$62.6 million increase in financial leases associated to rights of use of assets, mainly onerous concessions on land for the development of renewable energy generation projects. The transfer to the short-term of US$1.5 million under the long-term tolling agreement with TEN explains a small reduction in this account.

Other long-term liabilities: The US$11.8 million increase is explained by a US$15.7 million increase in deferred tax liabilities due to the application of instant depreciation, which was partially offset by a US$3.9 million reduction in the plant dismantling provision attributed to the dismantling works carried out at the coal-based units 12 and 13 in Tocopilla, which were decommissioned in 2019.

Shareholders' equity: The US$11.3 million increase in shareholders' equity is made up of (i) the US$54.7 million net income reported in 2021, (ii) the US$24 million cash equity contribution into Inversiones Hornitos by its former minority shareholder, and (iii) a US$29.2 million increase in TEN's equity value due to the mark-to-market adjustment on financial hedges. These increases were partially offset by the US$51 million final dividend paid in May 2021, the US$41.5 million provisional dividend paid in August 2021 and a lower mark-to-market variation of EECL's derivatives to hedge against foreign-exchange risk (US$4 million net of taxes).

APPENDIX 2

Financial information

	4Q19	1Q20	2Q20	3Q20	4Q20	1Q21	2Q21	3Q21	4Q21
EBITDA*	105.6	99.1	103.0	135.8	117.5	65.9	121.7	55.6	71.3
Net income attributed to the controller	-32.2	25.6	40.6	57.0	40.3	-17.6	47.6	8.7	8.7
Interest expense	12.5	28.5	10.6	10.5	9.9	52.2	16.8	8.9	10.9

* Operating income + Depreciation and Amortization for the period

	Dec/20	Dec/21
LTM EBITDA	455.3	314.5
LTM Net income attributed to the controller	163.5	47.4
LTM Interest expense	59.5	88.8
Financial debt	1,032.9	1,258.6
Current	68.6	106.2
Long-Term	964.3	1,152.4
Cash and cash equivalents	235.3	215.7
Net financial debt	797.6	1,042.9

Financial Ratios

	FINANCIAL RATIOS				
			Dec/20	Dec/21	Var.
LIQUIDITY	Current ratio (current assets / current liabilities)	(times)	1.44	1.55	***8%***
	Quick ratio ((current assets - inventory) / current liabilities)	(times)	1.20	1.15	***-4%***
	Working capital (current assets – current liabilities)	MMUS$	141.4	218.7	***55%***
LEVERAGE	Leverage ((current liabilities + long-term liabilities) / networth)	(times)	0.72	0.84	***17%***
	Interest coverage * ((EBITDA / interest expense))	(times)	7.66	3.54	***-54%***
	Financial debt –to- LTM EBITDA*	(times)	2.27	4.00	***76%***
	Net financial debt – to - LTM EBITDA*	(times)	1.75	3.32	***89%***
PROFITABILITY	Return on equity* (LTM net income attributed to the controller / net worth attributed to the controller)	%	7.5%	2.2%	***-71%***
	Return on assets* (LTM net income attributed to the controller / total assets)	%	4.4%	1.2%	***-73%***

*LTM = Last twelve months

As of December 31, 2021, the current ratio and the quick ratio were 1.55x and 1.15x, respectively, which compare with 1.44x and 1.20x at year-end 2020. The main reasons for these variations were the reduction of current liabilities; specifically, a decrease in employee liabilities and in the income tax provision. As a result, working capital, as measured by total current assets minus total current liabilities, increased. Liquidity remained strong due to the company's cash balances, cash generation ability, and low debt repayment commitments until January 2025.

The leverage ratio, as measured by total liabilities-to-equity, increased from 0.72x to 0.84x, mainly because of the full drawdown of the US$125 million IDB Invest loan and the increase in IFRS 16 financial leases explained by onerous concessions on land with the Ministry of Public Assets for the future development of renewable projects.

The interest coverage ratio for 2021, was 3.54x. Although this is a strong ratio, it represents a decrease compared to 7.66x at year-end 2020, mainly due to the EBITDA decrease and the exceptional increase in interest expense explained by the discount applied to the sale of long-term accounts receivable from regulated customers related to the price stabilization law.

The leverage ratio, as measured by Gross financial debt-to-EBITDA, increased to 4.0 times as a result of the new IDB Invest loan, an increase in IFRS16 financial leases and the EBITDA decrease. Net financial debt-to-EBITDA increased to 3.32x due to the debt increase and the decrease in EBITDA. Cash balances remained strong at US$215 million as of December 30, 2021.

Return on equity and return on assets reached 2.2% and 1.2%, respectively, a decrease compared to the ratios reported at year-end 2020 mainly because of the lower net income in 2021, which in turn resulted from lower EBITDA, one-shot interest expenses, and the accounting adjustment to the TEN investment, as explained above.

CONFERENCE CALL 2021

ENGIE Energía Chile is pleased to inform you that it will conduct a conference call to review its results for the year ended December 31, 2021, on Thursday February 3, 2022
at 10:00 a.m. (EST) – 12:00 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
+1(844) 686-3841 (toll free US)
https://hd.choruscall.com/?calltype=2&info=company&r=true

To join the conference, please state the name of the conference (**ENGIE ENERGIA**; no other Conference ID will be requested.
Please connect approximately 10 minutes prior to the scheduled starting time.

To access the phone replay, which will be available until February 15, 2022, please dial
+**1 (877) 344-7529** / +**1 (412) 317-0088**
Passcode I.D.: 10163441