Management Discussion and Analysis

This management discussion and analysis ("MD&A") of the financial condition and results of operations of SierraCol Energy Limited and its subsidiaries ("we", "our", "SCE" or the "Company") should be read in conjunction with the unaudited condensed consolidated financial statements for the period ended 31 December 2023 and 2022 and the notes thereto. Please read the full cautionary statements at the end of the document.

FY23 and 4Q23 performance highlights

Operational

Operational update

- FY23 SBR production of 43.0 kboed at the midpoint of the SBR production guidance of 42 – 44 kboed.
- 4Q23 Share Before Royalties ("SBR") production was 43.9 kboed, 2.2 kboed higher q/q. Production increased across all assets tied to development drilling and workover campaign results in the Llanos basin and La Cira Infantas recovery from surface equipment issues.
- In FY23, 42 new wells were drilled and completed and 70 workover jobs were executed. During the quarter, 19 wells were drilled and completed and 28 workover jobs were executed.
- During the quarter, 100% of the Caño Limón area production was shipped via the Caño Limón-Coveñas ("CLC") pipeline and 79% was shipped through this main pipeline in FY23.
- Successful exploration well in the Caño Limón area; the well had an initial flow rate of ~3,800 bod of light oil.

Replacing 1P and 2P reserves over 100%

- Reached a 113% 2P Reserves Replacement Ratio ("RRR"), achieving a replacement ratio record above 100% for the last 7 years. Delivered a solid 110% 1P RRR.
- 2P reserves of 118 million boe, and 1P reserves of 84 million boe, maintaining essentially flat our reserves life with a Reserves-to-Production ("R/P") ratio of 9.9 and 7.1 years, respectively.

Guidance 2024

- SBR production guidance for 2024 of 42 – 44 kboed.
- Capital and exploration expenditures guidance for 2024 of $170 – $200 million.

Committed to ESG goals and safe operations

- Achieved top-tier worldwide ESG rating by Sustainalytics for the second consecutive year, with a low-risk score of 19.9. SierraCol ranked 5th out of 315 global O&G companies.
- 47% reduction in net CO_2e emissions by year-end 2023, vs the 2020 baseline. On track to deliver a 60% reduction in net CO_2e emissions vs 2020 baseline by year-end 2024.
- Net emissions intensity factor improved from 33.4 in 2020 to 18.8 kg CO_2e/boe in 2023.
- 2023 Total Recordable Injury Rate ("TRIR") at 0.55, the best performance in the last 5 years and a 10% improvement vs 2022.

Financial

Financial metrics

- Average realised price of $76.3/boe vs Brent of $82.2/ bbl for FY23.
- Revenue from oil sales in FY23 was $918.5 million, down 14% y/y mainly due to lower realisations of $187.2 million partially offset by higher sale volumes of $32.3 million.
- Adjusted EBITDAX of $647.0 million for FY23, down 21% y/y, mainly driven by a 17% decrease in Brent y/y and a 33% increase in lifting cost y/y.
- Adjusted operating netback of $56.1/boe, and Operating netback of $53.6/boe for FY23.
- Capex for FY23 stood at $188.4 million, slightly below 2023 guidance of $190 - $210 million.
- Free Cash Flow of $170.8[1] million for FY23.

Ample liquidity and low net leverage

- Total available liquidity of $203.0 million (cash and cash equivalents of $88.7 million plus $114.3 million in undrawn amounts of committed credit lines).
- During 4Q23, the Company repaid $20.0 million outstanding under the RCF. After year-end $13.0 million was drawn down to support working capital requirements.
- Uncommitted credit lines of $171.0 million at year-end 2023.
- Net debt of $538.0 million with cash and cash equivalents of $88.7 million, and net leverage of 0.8x.
- Dividend payments of $100.0 million to the equity holder and $34.5 million to non-controlling interest during 2023.

Risk management

- On our Brent hedging programme until December 2024, we have hedged 52% of our hedgeable production, with a weighted average long put strike price of $63.4/bbl. We have no caps in our current programme.
- Regarding the currency hedging programme, we have hedged approximately 50% of the Company's cash needs in Colombian peso until 2Q24. We are employing zero-cost collars with a weighted average strike price of COP $4,125/ $4,701 and forward contracts with an average forward rate of COP $4,374.

Subsequent events

- Post year-end, Cedco, an affiliate of SCE, entered into an agreement to acquire Cepsa Colombia S.A. (Cepsa)'s participating interests in the contracts Caracara, Llanos 22, San Jacinto and Rio Páez, in Colombia. The 2022 audited net reserves for these assets added up to 7.7 million barrels of oil on a 2P basis. Closing of the transaction is subject to conditions precedent, including regulatory approvals, which can take several months. Until such time, Cepsa will continue to operate the assets.
- In early 2024, Cedco entered into a $74 million bilateral unsecured credit agreement with Grupo Bancolombia for the purpose of funding an asset acquisition and other general corporate purposes. Key terms of the agreement include maturity in June 2027 and a two-year grace period. As of the date of this document, the loan has not been drawn down.

[1] Free cash flow for FY23 presented before $45.0 million contingent payment to Oxy in 2Q23

Financial and operational results

Key figures

	4Q23	3Q23	4Q22[1]	Δ q/q	Δ y/y	FY23	FY22[1]	Δ y/y
Production & sales (kboed)								
Gross production	80.0	77.1	81.4	4%	-2%	79.5	81.4	-2%
SBR production[2]	43.9	41.7	44.2	5%	-1%	43.0	44.3	-3%
Net production	34.2	33.4	33.0	2%	4%	33.9	32.9	3%
Net sales	33.3	33.7	32.1	-1%	4%	33.1	32.1	3%
Operating netback per barrel of net sales ($/boe)								
Brent price	82.9	85.9	88.6	-4%	-7%	82.2	99.0	-17%
Realised price	78.7	81.3	81.3	-3%	-3%	76.3	91.9	-17%
Lifting cost	(20.6)	(22.8)	(16.5)	-9%	25%	(19.3)	(14.9)	30%
Transport cost	(1.1)	(1.0)	(0.8)	13%	41%	(0.9)	(0.9)	-4%
Adjusted operating netback per boe[2]	56.9	57.6	64.0	-1%	-11%	56.1	76.1	-26%
Administrative expenses	(4.7)	(2.8)	(4.4)	70%	6%	(3.4)	(3.2)	7%
Realised loss on oil derivatives	(0.4)	(0.5)	(0.3)	-10%	41%	(0.4)	(4.2)	-89%
Other[3]	3.7	1.2	(1.6)	208%	nm	1.3	0.8	63%
Operating netback[2]	55.6	55.6	57.7	–%	-4%	53.6	69.5	-23%
Adjusted EBITDAX ($ million)								
Total revenue	241.2	252.5	240.2	-4%	–%	921.5	1,076.2	-14%
Lifting cost	(63.2)	(70.7)	(48.7)	-11%	30%	(233.2)	(174.8)	33%
Transport cost	(3.5)	(3.1)	(2.5)	12%	39%	(10.4)	(10.3)	2%
Adjusted operating netback[2]	174.5	178.7	189.0	-2%	-8%	677.9	891.1	-24%
Administrative expenses	(14.3)	(8.5)	(12.9)	68%	11%	(41.5)	(37.6)	10%
Realised loss on oil derivatives	(1.3)	(1.5)	(1.0)	-11%	35%	(5.3)	(49.6)	-89%
Other[3]	11.5	3.7	(4.7)	207%	nm	16.0	10.2	56%
Adjusted EBITDAX[2]	170.4	172.4	170.5	-1%	–%	647.0	814.1	-21%
Key financial results ($ million)								
Net income	91.5	76.8	42.8	19%	114%	300.7	295.9	2%
Capex and exploration expenditures[2]	63.9	50.8	78.5	26%	-19%	188.4	204.9	-8%
Free Cash Flow[2]	133.0	(34.2)	112.4	nm	18%	170.8	401.2	-57%
Cash & cash equivalents	88.7	107.3	106.2	-17%	-16%	88.7	106.2	-16%
Net debt[2]	538.0	539.5	494.8	–%	9%	538.0	494.8	9%

[1] The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | [2] See "Non-IFRS Measures" section. | [3] Other includes prepaid expenses, other income/expenses (net), realised foreign exchange gain (loss), fair value remeasurements and non-recurring costs; in the fourth quarter, it includes other income of $7.8 million as a result of the estimation update in the decommissioning liability.

2023 year-end reserves audit results

The Company is providing the results of its annual independent reserves assessment, certified by DeGolyer and McNaughton ("D&M"), as of 31 December 2023, prepared in accordance with the Petroleum Resources Management System ("PRMS").

For FY23, SierraCol achieved an RRR of 113%, the highest since 2020, and an R/P ratio of 9.9 years, maintaining a healthy reserves life.

Reserves are presented as the Company's working interest after royalties.

2023 certified 2P reserves of 118 million boe, 99% oil, with an R/P ratio1 of 9.9 years, with a similar reserve life index vs 2022 (10.1 years), and an RRR of 113%. Certified 1P reserves stand at 84.3 million boe, with an R/P ratio of 7.1 years and an RRR of 110%.

PDP reserves: Proven developed producing reserves of 60.7 million boe, with an R/P ratio of 5.1 years.

PD Reserves: Proven developed reserves of 72.5 million boe, with an R/P ratio of 6.1 years.

1P Reserves: Proven reserves of 84.3 million boe, with an R/P ratio of 7.1 years.

2P Reserves: Proven plus probable reserves of 118 million boe, with an R/P ratio of 9.9 years.

3P Reserves: Proven plus probable plus possible reserves of 146 million boe, with an R/P ratio of 12.2 years.

The following table provides a reconciliation of SCE's 1P and 2P reserves:

million boe	1P	2P
31 December 2022	83.1	116.3
Production	-11.9	-11.9
Net additions	13.1	13.5
31 December 2023	84.3	118.0
R/P (years)	7.1	9.9
RRR (%)	110%	113%

The following table provides an overview of SCE's 1P and 2P reserves as of 31 December 2023 by area:

	2023		2022	
million boe	1P	2P	1P	2P
Caño Limón area	24.9	33.9	26.8	33.9
Middle Magdalena	52.1	67.5	49.1	65.9
Central Llanos	7.3	16.6	7.3	16.6
SCE	84.3	118.0	83.1	116.4

The following table shows the net present value discounted at 10% ("NPV10") after tax for 1P and 2P reserves:

As at 31 December 2023	1P	2P
Reserves (million boe)	84.3	118.0
NPV10 after tax ($ million)	1,344	1,707

The following table shows the Brent forecast used to estimate the reserves and NPV10 under PRMS:

	2024	2025	2026	2027
Brent ($/bbl)	87.8	83.0	80.5	81.6

For 2028 forward prices were escalated 2% per year, as well as the costs.

2024 Guidance

The company issues its 2024 production guidance as well as the capital and exploration expenditures guidance:

	2024 guidance
SBR production (kboed)	42 - 44
Capital and exploration expenditures ($ million)[2]	$170 – $200

Production

kboed	4Q23	3Q23	4Q22	Δ q/q	Δ y/y	FY23	FY22	Δ y/y
Gross production	80.0	77.1	81.4	4%	-2%	79.5	81.4	-2%
SBR production								
Caño Limón area	26.8	24.9	27.8	8%	-4%	26.0	28.0	-7%
Middle Magdalena	13.3	13.1	14.1	1%	-6%	13.6	13.7	-1%
Central Llanos	3.8	3.7	2.3	5%	68%	3.4	2.5	35%
SBR production	43.9	41.7	44.2	5%	-1%	43.0	44.3	-3%
Light and medium oil	43.3	40.9	43.4	6%	–%	42.3	43.7	-3%
Heavy oil	0.4	0.5	0.5	-11%	-19%	0.4	0.4	5%
Gas	0.2	0.2	0.2	-7%	-1%	0.3	0.2	36%
Royalties in kind	3.6	3.4	3.5	4%	2%	3.6	3.5	3%
Price-related effects	6.1	4.8	7.7	29%	-20%	5.5	7.9	-31%
Net production	34.2	33.4	33.0	2%	4%	33.9	32.9	3%

SBR production for FY23 was 43.0 kboed, at the midpoint of production guidance of 42-44 kboed. SBR production was down 3% compared to FY22 mainly driven by i) an impact of 2.0 kboed in the Caño Limón area as a result of delays in execution of activity during the first half of the year and ii) 0.2 kboed in La Cira Infantas linked to surface equipment failures and maintenance in the water injection and production system. This was partially offset by increased production of 0.9 kboed in Central Llanos after completion of a successful drilling program in 3Q23.

SCE achieved an exit rate of 45.6 kboed at the end of December 2023. The company implemented a successful drilling and workover program that resulted in increased activity execution in 4Q23 and a high exit rate.

[2] Guidance includes development, green and exploration capex plus exploration expenses.

SBR production for 4Q23 was 43.9 kboed, 5% higher than the previous quarter mainly due to i) increased production in the Caño Limón area (1.9 kboed) tied to the development drilling and workover campaign results, ii) better performance in the Central Llanos for the reasons explained above (0.2 kboed), and iii) ongoing recovery of La Cira Infantas production after the previous quarter surface equipment issues (0.1 kboed).

Compared to 4Q22, SBR production presented a minor decrease of less than 1% mainly due to: i) a lower production of 1.0 kboed in the Caño Limón area as a result of delayed drilling activity during the first half of the year, and ii) a lower production of 0.8 kboed in La Cira Infantas due to the impact of the previous quarter surface equipment failures. This was almost fully offset by 1.5 kboed of increased production in Central Llanos due to successful development activities in 2023.

SierraCol drilled a successful exploration well[3] in the Cosecha contract in the Caño Limón area. The REX-NE North well, which found oil in the M1 formation, was spud during 4Q23 and began production in January. The well had an initial flow rate of ~3,800 bod of light oil. Well testing is ongoing to further assess its potential.

Revenue

	4Q23	3Q23	4Q22	Δ q/q	Δ y/y	FY23	FY22	Δ y/y
Revenue ($ million)								
Oil sales	240.4	251.7	238.9	-5%	1%	918.5	1073.4	-14%
Natural gas sales	0.4	0.5	0.4	-15%	7%	2.0	1.4	45%
Services	0.4	0.3	0.9	43%	-50%	1.0	1.4	-29%
Total revenue	241.2	252.5	240.2	-4%	–%	921.5	1,076.2	-14%
Net sales (million boe)								
Oil sales	3.0	3.1	2.9	-1%	4%	12.0	11.7	3%
Natural gas sales	0.02	0.02	0.02	-14%	2%	0.08	0.05	44%
Net sales	3.1	3.1	3.0	-1%	4%	12.1	11.7	3%
Prices								
Brent ($/bbl)	82.9	85.9	88.6	-4%	-7%	82.2	99.0	-17%
Vasconia differential ($/bbl)	4.6	3.6	7.5	28%	-39%	5.4	5.0	8%
Average realised price ($/boe)	78.7	81.3	81.3	-3%	-3%	76.3	91.9	-17%

Revenue from oil sales of $918.5 million for FY23, down 14% y/y mainly due to a lower average realised price driven by a decrease in commodity prices ($180.9 million) and the net impact of the OBC pipeline usage of $0.5/boe[4] ($6.3 million), partially offset by an increase in volumes sold ($32.3 million).

Compared to 3Q23, revenue from oil sales decreased $11.3 million, mainly due to: i) a lower average realised price of $78.7/bbl vs $81.3/bbl with an impact of $8.4 million and ii) $2.9 million from a decrease in sales volume of 1% q/q.

Average realised price decreased $2.7/bbl q/q, mainly due to decrease in Brent of $3.1/bbl and larger Vasconia differential of $1.0/bbl; partially offset by a $1.4/bbl benefit linked to the increase in shipping via the CLC pipeline during the quarter (100% of Caño Limón production was shipped via CLC vs 80% in 3Q23).

Compared to 4Q22 revenue from oil sales remained essentially flat.

[3] The initial well classification is an [A-2] appraisal well, in accordance with the regulatory agency (ANH) classification guidelines.
[4] The net impact relating to the production shipped via the OBC pipeline assuming the transport cost SierraCol would have had to incur if 100% of the Caño Limón area production had been shipped via the CLC pipeline.

Operating expenses

$ million (unless otherwise stated)	4Q23	3Q23	4Q22	Δ q/q	Δ y/y	FY23	FY22	Δ y/y
Lifting cost	63.2	70.7	48.7	-11%	30%	233.2	174.8	33%
Transportation cost	3.5	3.1	2.5	12%	39%	10.4	10.3	2%
Operating expenses	66.7	73.8	51.2	-10%	30%	243.6	185.1	32%
Per barrel of net sales ($/boe)	21.7	23.8	17.3	-9%	25%	20.2	15.8	28%

Compared to FY22 lifting cost increased $58.4 million as a result of: i) $33 million impact of inflation over services and materials, ii) $9 million linked to higher share in operation expenses due to price clauses iii) $6 million of one-off expenses mainly associated with the development of the REX NE field, iv) $5 million primarily due to higher well work activity and a minor increase in energy consumption in La Cira Infantas and, v) $5 million of foreign exchange rate impact given a revaluation of the Colombian peso by 1% ($4216 USD/COP in FY23 vs $4266 in FY22). During 4Q23 we started to see a reduction in lifting costs which were the result of actions implemented during second half of 2023.

Lifting cost decreased by $7.5 million q/q mainly due to i) $7 million due to timing effects associated with 3Q23 one-off costs, ii) $0.7 million tied to lower well work costs and activity in La Cira Infantas; partially offset by higher energy consumption due to fluid increase in 4Q23.

Compared to 4Q22 lifting cost was $14.5 million higher primarily driven by i) $10.9 million of foreign exchange rate impact given a revaluation of the Colombian peso by 18% ($3,937 USD/COP in 4Q23 vs $4,824 in 4Q22) ii) $9.0 million impact of inflation over services and materials, partially offset by $6 million mainly due to lower well work in 4Q23.

Transport cost increased $0.4 million q/q due to higher evacuation through the CLC pipeline and $1.0 million vs 4Q22 mainly due to higher shipped volumes.

Absolute operating expenses decreased 10% vs 3Q23 and the cost per barrel decreased 9%.

Absolute operating expenses vs 4Q22 and FY22 increased 30% and 32%, while the net cost per barrel increased 25%, and 28%, respectively.

Adjusted operating netback per boe

$/boe of net sales	4Q23	3Q23	4Q22	Δ q/q	Δ y/y	FY23	FY22	Δ y/y
Realised price	78.7	81.3	81.3	-3%	-3%	76.3	91.9	-17%
Lifting cost	(20.6)	(22.8)	(16.5)	-9%	25%	(19.3)	(14.9)	30%
Transport cost	(1.1)	(1.0)	(0.8)	13%	41%	(0.9)	(0.9)	-4%
Adj. operating netback per boe	56.9	57.6	64.0	-1%	-11%	56.1	76.1	-26%

Adjusted operating netback per boe decreased 11% and 26% compared to 4Q22 and FY22, respectively, as a result of lower realised prices and an increase in operating expenses.

Adjusted operating netback decreased 1% q/q, as a result of the lower realised price partly offset by a 9% decrease in operating expenses explained in the previous section.

Administrative expenses

$ million	4Q23	3Q23	4Q22	Δ q/q	Δ y/y	FY23	FY22	Δ y/y
Administrative expenses	14.3	8.5	12.9	68%	11%	41.5	37.6	10%

Administrative expenses of $41.5million for FY23, up $3.9 million y/y mainly due to: i) higher personal expenses and ii) lower overhead recoveries from partners.

Administrative expenses increased $5.8 million q/q mainly due to seasonality of professional fees and one-off adjustments in the fourth quarter (non-cash items).

Compared to 4Q22 administrative expenses increased $1.4 million mainly due to foreign exchange rate resulting from the 18% Colombian peso revaluation ($3,937 USD/COP in 4Q23 vs $4,824 in 4Q22).

Capital expenditures

$ million	4Q23	3Q23	4Q22[1]	Δ q/q	Δ y/y	FY23	FY22[1]	Δ y/y
Caño Limón area	28.0	28.9	22.7	-3%	24%	88.7	63.1	41%
Middle Magdalena	19.8	16.6	31.8	19%	-38%	49.1	81.2	-39%
Central Llanos	8.3	3.8	17.2	116%	-52%	37.5	25.2	49%
Development capex	56.1	49.4	71.6	14%	-22%	175.3	169.5	3%
Exploratory drilling	6.5	0.4	5.2	>1000%	26%	7.9	31.1	-75%
Total capex	62.6	49.8	76.8	26%	-18%	183.2	200.6	-9%
Exploration expenses[2]	1.3	1.0	1.7	36%	-24%	5.1	4.2	21%
Capex and exploration expenditures	63.9	50.8	78.5	26%	-19%	188.4	204.9	-8%

[1] The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | [2] Exploratory expenses are presented net of dry hole costs and impairments.

Compared to FY22, development capex increased 3%, mainly due to deeper wells in the Caño Limón area and higher drilling and workover activity in Central Llanos, partially offset by lower activity in Middle Magdalena and drilling cost efficiencies in connection with new technology and well design implementation. 43 development wells drilled and completed and 79 workover jobs were executed during FY23 vs 62 wells drilled and completed and 94 workover jobs during FY22.

Development capex increased $6.8 million q/q, mainly driven by the receipt of Battery Energy Storage System equipment in Central Llanos and the construction of an electrical line in the REX NE field in the Caño Limón area as part of the Company's energy transition programme, and additional wells activity in Middle Magdalena. 19 development wells drilled and completed (2 wells in the Caño Limón area and 17 wells in Middle Magdalena area) vs 12 wells drilled and completed in the previous quarter; 28 workover jobs were executed during 4Q23 vs 28 workover jobs during 3Q23.

Compared to 4Q22 development capex decreased 22%, mainly driven by lower drilling activity in the Middle Magdalena and Central Llanos areas.

Exploratory drilling in FY23 decreased 75% vs FY22 primarily due to reduced activity (2 exploration wells were drilled compared to 3 wells in FY22) with a focus on shallow wells throughout 2023. Exploratory drilling increased $6.1 million q/q primarily driven by higher exploratory activity in connection with a successful exploration well in the Caño Limón area.

Capital and exploration expenditures totalled $188.4 million in FY23, slightly below 2023 guidance $190 - $210 million.

Adjusted EBITDAX and Free Cash Flow

$ million	4Q23	3Q23	4Q22[1]	Δ q/q	Δ y/y	FY23	FY22[1]	Δ y/y
Total comprehensive income	88.4	76.8	45.6	15%	94%	297.6	298.7	–%
Financial income and financial expenses	6.1	7.7	8.9	-21%	-32%	29.3	35.8	-18%
Depreciation, depletion and amortisation	33.1	32.2	32.2	3%	3%	128.9	114.4	13%
Income tax expense	24.4	37.4	70.1	-35%	-65%	147.6	281.1	-47%
Exploration expenses and dry hole cost	13.1	0.6	6.8	>1000%	93%	17.3	65.8	-74%
Foreign exchange (income) / loss	(20.4)	0.9	(3.3)	nm	518%	(15.1)	(4.1)	266%
Accretion of decommissioning liability	0.3	1.1	(0.4)	-73%	nm	3.4	4.1	-16%
Prepaid expenses and bond cost amortisation	3.2	5.4	2.8	-41%	15%	13.9	12.3	13%
Unrealised fair value gain on derivatives	(0.7)	1.3	(0.7)	nm	3%	–	(7.4)	-100%
Inventory fluctuation	0.4	6.7	(0.6)	-94%	nm	(0.9)	0.4	nm
Fair value remeasurements	3.1	–	(1.4)	–%	nm	3.1	2.5	22%
Other non-cash items	19.4	2.3	10.5	759%	84%	21.8	10.5	107%
Adjusted EBITDAX	170.4	172.4	170.5	-1%	–%	647.0	814.1	-21%
Exploration drilling[2]	(6.5)	(0.4)	(5.2)	>1000%	26%	(7.9)	(31.1)	-75%
Exploration and seismic expense	(1.2)	(1.0)	(1.7)	29%	-28%	(5.1)	(4.2)	20%
Tax payments	–	(117.3)	–	-100%	–%	(197.1)	(132.1)	49%
Capital expenditures[2]	(56.1)	(49.4)	(71.6)	14%	-22%	(175.3)	(169.5)	3%
Acquisition of PUT-36	–	–	–	–%	–%	–	(10.0)	-100%
Inventory of capitalizable parts/	0.6	(3.3)	–	nm	–%	(2.7)	(2.9)	-5%
Decommissioning funding	–	–	(2.3)	–%	-100%	–	(2.3)	-100%
Change in working capital[3]	31.4	(40.0)	29.3	nm	7%	(99.3)	(50.1)	98%
Non-recurring costs	(1.8)	–	(1.5)	–%	19%	(1.8)	(1.5)	19%
Realised FX rate gain (loss)	(3.6)	4.9	(4.5)	nm	-20%	14.3	(5.4)	nm
Lease payments	(0.2)	(0.1)	(0.5)	12%	-71%	(1.3)	(3.7)	-66%
Free Cash Flow	133.0	(34.2)	112.4	nm	18%	170.8	401.2	-57%

[1] The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | [2] Figures including capital and exploration drilling accruals | [3] Figures excluding capital and exploration drilling accruals.

Adjusted EBITDAX for FY23 was $647.0 million, resulting in an Operating netback of $53.6/boe.

Adjusted EBITDAX decreased 1% q/q mainly due to a decrease of $3.1/bbl in Brent partially offset by decreased operational expenses.

Free Cash Flow totalled $133.0 million in the quarter mainly driven by lower tax payments (nil in 4Q23 vs $117.3 million in 3Q23) and increase in working capital q/q is mainly attributed to lower accounts receivable driven primarily by volumes paid by customers, and increase in accounts payable as a result of higher activity in fourth quarter [5].

[5] See note 11 of the consolidated financial statements for the period ended 31 December 2023.

Free Cash Flow of 170.8[6] million for FY23, after $188.4 million of capital and exploration expenditures, $197.1 million of tax payments and working capital changes of $99.3 million mainly driven by the 2023 income tax advanced payment of $72 million, and withholding taxes of $20 million as a result of incremental rates.

Cash flows

The table summarises the classification of our cash flows for FY23 and FY22:

$ million	FY23	FY22
Net cash flows from operating activities	345.2	595.3
Net cash flows used in investing activities	(204.9)	(234.3)
Net cash flows from financing activities	(160.6)	(375.2)
Increase in cash and cash equivalents during the period	(20.2)	(14.1)
Cash and cash equivalents at the beginning of the period	106.2	119.3
Effect of foreign exchange on cash and cash equivalents held in foreign currencies	2.7	1.0
Cash and cash equivalents at the end of the period	88.7	106.2

As presented in the audited consolidated statement of cash flows within the Financial Statements document:

Cash flows from operating activities for FY23 of $345.2 million is presented net of cash taxes paid of $197.1 million. Cash flows used in investing activities include cash additions of $169.5 million to property, plant and equipment ("PPE") and $3.7 million to exploration and evaluation assets, a $45.0 million contingent payment to Oxy, and financial income of $13.3 million. Cash flows from financing activities include dividends paid to Company shareholders of $100 million, dividends paid to non-controlling interest of $34.5 million, an outstanding short-term debt of $20.0 million, interest and financial expenses paid of $43.0 million, and lease payments of $1.3 million.

Cash and cash equivalents at year-end were $88.7 million.

[6] FY23 working capital change of $99.3 million mainly driven by the 2023 income tax advanced payment of $72 million, and withholding tax of $20 million as a result of incremental rates.

Liquidity and capital resources

The following table shows our total liquidity for FY23 and FY22:

$ million (unless stated)	FY23	FY22
RCF	120.0	80.0
Short-term credit line	20.0	–
Total committed credit lines	140.0	80.0
Drawn amount of the RCF	–	–
Drawn amount of short-term credit lines	(20.0)	–
Total drawn amounts of committed credit lines	(20.0)	–
Amount used towards letters of credit	(5.0)	(16.1)
COP devaluation effect[7]	(0.7)	(6.7)
Available amount of committed credit lines	114.3	57.1
Cash and cash equivalents	88.7	106.2
Total liquidity	203.0	163.3

The following table shows total indebtedness, net debt and net leverage for FY23 and FY22:

$ million (unless stated)	FY23	FY22
2028 senior notes @ 6.00%	600.0	600.0
Drawdown of short-term debt	20.0	–
Capital lease obligations	6.7	1.0
Total indebtedness	626.7	601.0
(-) Cash & cash equivalents	88.7	106.2
(=) Net debt	538.0	494.8
LTM Adjusted EBITDAX	647.0	814.1
Net leverage (x)	0.8x	0.6x

We ended FY23 with an ample liquidity, closing at $203.0 million, and maintaining a low net leverage at 0.8x.

During the fourth quarter, the Company repaid $20.0 million outstanding under the Revolving Credit Facility ("RCF"). At year-end, the $20.0 million BTG Pactual short-term credit line was outstanding.

Subsequent to the year-end, the Company released from the RCF the total amount used towards letters of credit ($5.0 million), and $13.0 million was drawn down to support working capital requirements.

[7] 25% of the current aggregate principal amount under the RCF is peso-denominated.

Summary of quarterly results[1

	4Q23	3Q23	2Q23	1Q23	4Q22	3Q22	2Q22	1Q22
Production & sales (kboed)								
Gross production	80.0	77.1	77.9	83.2	81.4	80.1	78.4	85.8
SBR production[(2)]	43.9	41.7	41.9	44.6	44.2	43.5	42.8	46.7
Net production	34.2	33.4	33.2	34.9	33.0	32.0	31.2	35.3
Net sales	33.3	33.7	31.3	34.0	32.1	30.3	30.9	35.0
Operating netback per barrel of net sales ($/boe)								
Brent price	82.9	85.9	77.7	82.1	88.6	97.7	112.0	97.9
Realised price	78.7	81.3	70.4	74.2	81.3	92.6	103.8	90.7
Lifting cost	(20.6)	(22.8)	(18.9)	(14.8)	(16.5)	(16.8)	(13.9)	(12.8)
Transport cost	(1.1)	(1.0)	(0.6)	(0.7)	(0.8)	(0.9)	(0.9)	(0.8)
Adjusted operating netback per boe[(2)]	56.9	57.6	50.9	58.6	64.0	74.9	89.0	77.1
Administrative expenses	(4.7)	(2.8)	(3.0)	(3.3)	(4.4)	(1.9)	(3.3)	(3.3)
Realised loss on oil derivatives	(0.4)	(0.5)	(0.5)	(0.4)	(0.3)	(1.0)	(10.0)	(5.6)
Other[(3)]	3.7	1.2	(1.3)	1.4	(1.6)	1.9	2.0	1.4
Operating netback[(2)]	55.6	55.6	46.1	56.4	57.7	73.9	77.7	69.6
Adjusted EBITDAX ($ million)								
Total revenue	241.2	252.5	200.5	227.3	240.2	258.2	291.8	286.0
Lifting cost	(63.2)	(70.7)	(53.9)	(45.4)	(48.7)	(46.8)	(38.9)	(40.4)
Transport cost	(3.5)	(3.1)	(1.6)	(2.2)	(2.5)	(2.5)	(2.6)	(2.6)
Adjusted operating netback[(2)]	174.5	178.7	144.9	179.7	189.0	208.9	250.3	242.9
Administrative expenses	(14.3)	(8.5)	(8.6)	(10.1)	(12.9)	(5.3)	(9.2)	(10.2)
Realised loss on oil derivatives	(1.3)	(1.5)	(1.3)	(1.2)	(1.0)	(2.8)	(28.2)	(17.5)
Other[(3)]	11.5	3.7	(3.6)	4.4	(4.7)	5.0	5.6	4.2
Adjusted EBITDAX[(2)]	170.4	172.4	131.4	172.8	170.5	205.8	218.5	219.4
Key financial results ($ million)								
Net income	88.4	76.8	56.6	75.8	45.6	80.9	85.6	86.6
Capex and exploration expenditures[(2)]	63.9	50.8	44.5	29.2	78.5	55.3	32.8	38.3
Free Cash Flow[(2)]	133.0	(34.2)	9.2	62.8	112.4	131.6	27.4	129.9
Cash & cash equivalents	88.7	107.3	173.2	115.2	106.2	302.5	189.8	178.4
Net debt[(2)]	538.0	539.5	497.8	490.8	494.8	300.7	414.4	426.7

[(1)] The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | [(2)] See "Non-IFRS Measures" section. | [(3)] Other includes prepaid expenses, other income/expenses (net), realised foreign exchange gain (loss), fair value remeasurements and non-recurring costs.

Risk management contracts

Brent hedging

Our commodity hedging programme seeks to protect the oil price downside risk on a significant portion of our underlying cash flows, while avoiding speculative positions and leaving room for potential upside. The Company's target is to hedge between 40% to 60% of its expected hedgeable production, six to twelve months ahead.

The table below provides a summary of the current commodity hedging positions as of the date of this document:

Type of Instrument	Term	Benchmark	Volume (bbl)	Avg. long put strike price ($/bbl)
Put	Jan-24 to Aug-24	Brent	3,929,633	65.0
Put	Sep-24 to Dec-24	Brent	1,841,025	60.0

As of the date of this document, we have hedged 52% of our hedgeable production until December 2024, with a weighted average long put strike price of $63.4/bbl.

We will continue to monitor the market and exercise our judgement to enter into new hedging positions when we consider appropriate.

Currency hedging

We have currently open currency hedging positions to manage volatility in the foreign exchange rate of Colombian peso to US dollar, hedging approximately 50% of the Company's cash needs in Colombian peso.

The table below provides a summary of the current currency hedging positions as of the date of this document:

Type of Instrument	Term	Benchmark	Volume ($ million)	Avg. Put / Call	Avg. Forward rate
Zero-cost collar	Jan-24 to Mar-24	COP / USD	$45.0	4,067 / 4,623	
Zero-cost collar	Apr-24 to Jun-24	COP / USD	$45.0	4,183 / 4,778	
	1Q24 - 2Q24	COP / USD	$90.0	4,125 / 4,701	
Forward	Feb-24	COP / USD	$16.2		4,306
Forward	Apr-24	COP / USD	$51.5		4,360
Forward	Jun-24	COP / USD	$51.0		4,410
	1Q24 - 2Q24	COP / USD	$118.7		4,374

We will continue to actively monitor market conditions and we may continue to hedge local currency to manage volatility in the foreign exchange rate of the Colombian peso to US dollar.

Non-IFRS Measures

This MD&A contains non-IFRS financial measures and ratios, including Adjusted EBITDAX and Free Cash Flow that are not required by, or presented in accordance with, IFRS. Management uses these measures to evaluate operating performance of the Company and as a basis for strategic planning and forecasting, as well as monitoring certain aspects of our cash flow and liquidity. We also believe they provide useful information to investors, securities analysts and other interested parties as supplemental measures of performance.

These non-IFRS measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS.

Adjusted EBITDAX: calculated as comprehensive income or loss adjusted for financial income and financial expenses, depreciation, depletion and amortisation, impairment of property, plant and equipment and inventory, income tax expense, exploration and seismic expenses and dry hole cost, foreign exchange income or loss and other non-cash items excluding other comprehensive income and other adjustments relating to differences in the recognition of revenues and costs which are excluded in order to represent the earnings on a cash basis.

Adjusted operating netback: calculated as total revenue less lifting and transportation costs.

Adjusted operating netback per boe: calculated as average realised price less operating expenses per boe of net sales.

Capex and exploration expenditures: calculated as development capex plus exploratory drilling plus exploration expenses.

Net debt: calculated as total financial indebtedness less cash and cash equivalents. Total financial indebtedness includes the nominal value of the 2028 senior notes plus drawn amounts of credit lines plus capital lease obligations.

Net leverage: calculated as net debt divided by last twelve-months (''LTM'') Adjusted EBITDAX.

Free Cash Flow ("FCF"): consists of Adjusted EBITDAX further adjusted for exploration expenses and tax payments, capital expenditures, decommissioning funding, changes in working capital, realised foreign exchange income or loss, lease payments and non-recurring costs.

Operating netback per boe: calculated as Adjusted EBITDAX divided by net sales.

Share Before Royalties ("SBR") production: Company's working interest production before discounting royalties to government and high-price clause participation royalties (price-related effects).

Total available liquidity: calculated as the sum of cash and cash equivalents plus undrawn amounts of committed credit lines.

Vasconia differential: Vasconia FOB Colombia vs Latin America Brent Futures strip (close) reported by Platts, code AAXCB00.

Cautionary Statements

This management discussion and analysis (“MD&A”) of the financial condition and results of operations of SierraCol Energy Limited and its subsidiaries (“we,” “our”, “SCE” or the “Company”) should be read in conjunction with the audited consolidated financial statements for the period ended 31 December 2023 and the notes thereto. This MD&A includes statements regarding industry outlook, our expectations regarding the performance of our business and other forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to numerous risks and uncertainties, many of which are beyond our control. Our actual results may differ materially from those contained in or implied by any forward-looking statements.

Sales volumes can differ from our net entitlement to production of saleable hydrocarbons due to over- or under-lifting of our production entitlement in any single accounting period. The quantities of over- and under-lifted production entitlement are not considered material to the overall production figures in any period. Where gross amounts are indicated, they are presented on a total basis—i.e., the actual interest of the relevant license holder in the relevant fields and licence areas without deduction for the economic interest of commercial partners, government production shares, taxes or royalty interests or other deductions. Our legal interest and effective working interest in the relevant fields and licence areas are disclosed separately. Unless otherwise indicated, our production, reserves and resources figures are presented on a basis including our ownership share of volumes of companies that we account for under the equity accounting method.

Certain amounts and percentages included in this document have been rounded for ease of presentation. Accordingly, figures shown as totals or percentage changes between periods may not be the arithmetic result of their inputs as presented in this document.

The best-in-class netback statement is based on our own calculations employing information from Company filings for peers. “Peers” are Latin American oil and gas companies that are focused on Colombia and are listed and/or rated by credit rating agencies.

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