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 March 2023 and the notes thereto. Please read the full cautionary statements at the end of the document.

1Q23 Performance Highlights

Operational

Strong performance

- Share Before Royalties ("SBR") production was 44.6 kboed in 1Q23, up 1% vs 4Q22 mainly due to production of new wells in Central Llanos and production increase in the Caño Limón area.
- During 1Q23, 2 active rigs drilled and completed 9 new wells: 2 in the Caño Limón area, 6 in Middle Magdalena and 1 in Central Llanos. In addition, 8 workovers were completed in 1Q23.
- 85% of the Caño Limón area production was shipped through the Caño Limón-Coveñas pipeline ("CLC"). The remaining 15% of crude oil from the Caño Limón area was shipped through the alternative Bicentenario pipeline ("OBC") during the quarter.
- Completed the Infantas Oriente 3D seismic survey at La Cira Infantas. The seismic processing is ongoing.

Committed to ESG goals and safe operations

- After-quarter end, we released the 2022 sustainability report on 15 May.
- SierraCol is making progress to deliver on its target of 50% reduction in net CO_2e emissions by year-end 2023 vs the 2020 baseline.
- In 1Q23, the regulator approved the installation of a fourth transformer of 50 MVAs in Caño Limón, which will enable SierraCol to replace the final 16 MW of crude-based power generation with electricity from the national grid. Construction has commenced in the field.
- In 2021 SierraCol committed to eliminating gas flaring by 2025. In 1Q23, we took the decision to bring this forward by approving two key projects: a) two gas to liquids conversion projects in the Caño Limón area and b) a new gas compressor in Caricare. These projects will allow SierraCol to significantly accelerate the routine gas flaring elimination in its operations.
- In 1Q23 SierraCol submitted the first methane measurement report to ANH, showing lower levels than had been previously estimated using modelling software. Mitigation actions for fugitive methane emissions are being implemented during 2023.

Financial

Robust results

- Average realised price of $74.2/boe vs Brent of $82.1/bbl for 1Q23.
- Revenue from crude oil sales in 1Q23 was $226.7 million, down 5% vs 4Q22 mainly due to lower realised price q/q ($20.6 million) partially offset by higher volumes sold ($8.4 million).
- Net income of $75.8 million in 1Q23, up 66% vs 4Q22 mainly due to a lower deferred tax expense and better operational performance.
- Adjusted operating netback of $58.6/boe for 1Q23, down 8% q/q mainly as a result of lower Brent.
- Adjusted EBITDAX of $172.8 million ($56.4/boe) for 1Q23, up 1% q/q despite a $6.5/bbl decrease in Brent.
- Last twelve-months ("LTM") Adjusted EBITDAX of $767.5 million, down 6% q/q mainly due to lower Brent.
- Free Cash Flow of $62.8 million for 1Q23[1], down 45% q/q mainly due to a $71 million reduction of accounts payable and tax payments of $18.2 million.
- Capital and exploration expenditures of $29.2 million for 1Q23, down 62% vs 4Q22.

Ample liquidity and low net leverage

- Net debt of $490.8 million with cash and cash equivalents of $115.2 million at 1Q23.
- Net leverage of 0.6x.
- Total available liquidity at quarter-end was $198.4 million (cash and cash equivalents of $115.2 million plus $83.1 million in undrawn amounts of committed credit lines).
- After quarter-end, some lenders increased their commitments under the RCF by $40 million. The aggregate principal amount of commitments provided under the RCF is now $120.0 million[2].
- During the quarter, an additional $20 million short-term credit line was secured to support working capital requirements. The full amount was drawn down and received on 3 April, after quarter-end, taking advantage of lower interest rates vs the RCF.
- During 1Q23, the second payment of the Oxy contingent consideration of $45 million was made.
- Completed dividend payments of $8.8 million to non-controlling interest during the quarter.

Risk management

- For the period of 1Q23-3Q23 we have hedged 50% of our hedgeable production, with a weighted average long put strike price of $63.7/bbl.
- For 1H23, to remove put spread floors, we have entered into new zero-collar options over 37% of our hedgeable production, with a weighted average call strike price of $120.2/bbl.
- We entered into currency hedging positions of $148 million in 1H23. We currently employ zero-cost collar options and forwards.

[1] Free Cash Flow for 1Q23 presented before $45.0 million contingent payment to Oxy.
[2] The updated amount of the RCF is $120.0 million of which 25% is Colombian peso-denominated at the issuance rate of COP 3,700/USD.

Financial and Operational Results

Key Figures

	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Production & sales (kboed)					
Gross production	83.2	81.4	85.8	2%	-3%
SBR production[3]	44.6	44.2	46.7	1%	-4%
Net production	34.9	33.0	35.4	6%	-1%
Net sales	34.0	32.1	35.0	6%	-3%
Operating netback per barrel of net sales ($/boe)					
Brent price	82.1	88.6	97.9	-7%	-16%
Realised price	74.2	81.3	90.7	-9%	-18%
Lifting cost	(14.8)	(16.5)	(12.8)	-10%	16%
Transport cost	(0.7)	(0.8)	(0.8)	-9%	-9%
Adjusted operating netback per boe[3]	58.6	64.0	77.1	-8%	-24%
Administrative expenses	(3.3)	(4.4)	(3.3)	-25%	–%
Realised loss on oil derivatives	(0.4)	(0.3)	(5.6)	34%	-93%
Other[4]	1.4	(1.6)	1.4	nm	–%
Operating netback[3]	56.4	57.7	69.6	-2%	-19%
Adjusted EBITDAX ($ million)					
Total revenue	227.3	240.2	286.0	-5%	-21%
Lifting cost	(45.4)	(48.7)	(40.4)	-7%	12%
Transport cost	(2.2)	(2.5)	(2.6)	-10%	-15%
Adjusted operating netback[3]	179.7	189.0	242.9	-5%	-26%
Administrative expenses	(10.1)	(12.9)	(10.2)	-22%	-2%
Realised loss on oil derivatives	(1.2)	(1.0)	(17.5)	28%	-93%
Other[4]	4.4	(4.7)	4.2	nm	4%
Adjusted EBITDAX[3]	172.8	170.5	219.4	1%	-21%
Supplementary financial results ($ million)					
Net income	75.8	45.6	86.6	66%	-13%
Capex and exploration expenditures[3]	29.2	78.5	38.3	-63%	-24%
Free Cash Flow[3]	62.8	113.3	128.6	-45%	-51%
Cash & cash equivalents	115.2	106.2	178.4	9%	-35%
Net debt[3]	490.8	494.8	426.7	-1%	15%

[3] See "Non-IFRS Measures" section.
[4] Other includes prepaid expenses, other income/expenses (net), realised foreign exchange gain (loss), fair value remeasurements and non-recurring costs.

2023 Guidance

The following table presents the Company's 2023 production and capital and exploration expenditures guidance:

	2023
SBR production (kboed)	43 – 45
Capital and exploration expenditures ($m)[5]	$190 – $210

Production

kboed	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Gross production	83.2	81.4	85.8	2%	-3%
SBR production					
Caño Limón area	28.0	27.8	29.5	0%	-5%
Middle Magdalena	14.0	14.1	14.4	0%	-2%
Central Llanos	2.6	2.3	2.8	16%	-6%
SBR production	44.6	44.2	46.7	1%	-4%
Light and medium oil	43.9	43.4	46.0	1%	-5%
Heavy oil	0.4	0.5	0.4	-20%	-1%
Gas	0.3	0.2	0.2	33%	33%
Royalties in kind	3.8	3.5	3.8	7%	-2%
Price-related effects	6.0	7.7	7.5	-21%	-19%
Net production	34.9	33.0	35.4	6%	-1%

SBR production was 44.6 kboed in 1Q23, within production guidance of 43 – 45 kboed. SBR production increased by 1% vs 4Q22 primarily driven by a 0.4 kboed increase in Central Llanos due to production from new wells, and a 0.1 kboed increase in the Caño Limón area due to strong performance from the 2022 wells campaign and other development activity.

Compared to 1Q22, SBR production decreased by 4% due mainly to i) -0.9 kboed due to change in working interest in the Rondón field in the Caño Limón area, from 50% to 35% under the terms of the Rondón Contract extension ii) -0.6 kboed in the Caño Limón area as a result of natural base decline partially offset by strong production results in new wells and workover campaign iii) -0.3 kboed in La Cira Infantas field caused by minor electrical events and iv) -0.2 kboed in Central Llanos due to delays in the incremental activity and downhole failures in certain wells.

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

Revenue

	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Revenue ($ million)					
Oil sales	226.7	238.9	285.1	-5%	-20%
Natural gas sales	0.5	0.4	0.4	44%	27%
Services	0.1	0.9	0.4	-93%	-83%
Total revenue	227.3	240.2	286.0	-5%	-21%
Net sales (mboe)					
Oil sales	3.0	2.9	3.1	4%	-3%
Natural gas sales	0.02	0.02	0.02	35%	35%
Net sales	3.1	3.0	3.2	4%	-3%
Prices					
Brent ($/bbl)	82.1	88.6	97.9	-7%	-16%
Vasconia differential ($/bbl)	7.9	7.5	3.6	5%	119%
Average realised price ($/boe)	74.2	81.3	90.7	-9%	-18%

Revenue from oil sales decreased 5% q/q, $12.2 million, mainly due to a lower average realised price of $74.2/bbl vs $81.3/bbl, with a price impact of $19.6 million, partly offset by $8.4 million from an increase in sales volume of 4% q/q.

Average realised price decreased 9% q/q, mainly due to a decrease in Brent. The Vasconia differential increased by $0.4/bbl, decreasing price realisation by the same amount.

Compared to 1Q22, revenue from oil sales decreased 20% y/y, mainly due to a lower average realised price driven by decreasing commodity prices, along with a wider Vasconia differential (an impact of $36.8 million and $13.0 million, respectively), and to lower sold volumes (an impact of $8.6 million).

Operating Expenses

$ million (unless otherwise stated)	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Lifting cost	45.4	48.7	40.4	-7%	12%
Transportation cost	2.2	2.5	2.6	-10%	-15%
Operating expenses	47.6	51.2	43.0	-7%	11%
Per barrel of net sales ($/boe)	15.6	17.3	13.6	-10%	14%

Lifting cost decreased 7% q/q mainly due to lower maintenance activity, a lower number of workovers and well services after a ramp up of operational activity during last quarter, and some delayed activity to 2Q23.

Compared to 1Q22, lifting cost was 12% higher. This is mainly as a result of: i) an increase in purchased energy in the Caño Limón area given the replacement of crude-based power generation with electricity from the national grid – which is more than offset by the sale of barrels previously used for self-consumption – along with an increase in energy tariffs, ii) a higher activity in well interventions and a fishing job in Central Llanos, and iii) higher equipment maintenance activities in Central Llanos. These increases were partly offset by foreign exchange benefit.

Transportation cost decreased $0.3 million q/q and $0.4 million y/y due to reduced evacuation through the CLC pipeline. The impact of the use of the OBC pipeline is reflected in the lower realisation price of the quarter by $0.4/bbl.

Absolute operating expenses decreased 7% vs 4Q22 while the cost per barrel decreased by 10%, as net sales increased 4% q/q.

Absolute operating expenses increased 11% vs 1Q22, while the cost per barrel increased 14%, as net sales contracted by 3%.

Adjusted Operating Netback

$/boe of net sales	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Realised price	74.2	81.3	90.7	-9%	-18%
Operating expenses	(15.6)	(17.3)	(13.6)	-10%	14%
Adj. Operating netback	58.6	64.0	77.0	-8%	-24%

Adjusted operating netback decreased 8% q/q, as a result of the lower realised price partly offset by the 10% decrease in operating expenses explained in the previous section.

Compared to 1Q22, Adjusted operating netback per barrel decreased 24%, as a result of lower realised prices and an increase in operating expenses.

Administrative Expenses

$ million	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Administrative expenses	10.1	12.9	10.2	-22%	-2%

Administrative expenses decreased 22% q/q mainly due to seasonality of professional fees, which are typically higher in the fourth quarter of the year.

Compared to 1Q22 administrative expenses remained essentially flat y/y.

Capital Expenditures

$ million	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Caño Limón area	9.4	22.7	14.1	-59%	-33%
Middle Magdalena	6.7	31.8	12.9	-79%	-48%
Central Llanos	10.9	17.2	1.0	-36%	>1000%
Development capex	27.0	71.6	27.9	-62%	-3%
Exploratory drilling	0.1	5.2	9.6	-97%	-99%
Total capex	27.1	76.8	37.5	-65%	-28%
Exploration expenses*	2.1	1.7	0.8	19%	165%
Capex and exploration expenditures	29.2	78.5	38.3	-63%	-24%

*Exploratory expenses are presented net of dry hole costs and impairments.

Development capex decreased 62% q/q, as a result of lower drilling and workover activity across all assets after a ramp up of operational activity during last quarter, and some delayed activity to 2Q23. 19 drilled and completed wells during 4Q22 vs 9 wells in 1Q23, and 46 jobs during 4Q22 vs 8 jobs in 1Q23, following a typical cycle of a year's business plan, whereby significant activity in the last quarter precedes a relative slowdown in the first quarter of the following year.

Compared to 1Q22 development capex decreased 3%, mainly due to slower pace activity in the Caño Limón area and Middle Magdalena, partly offset by increased activity in Central Llanos.

Exploratory expenses added $2.0 million during 1Q23 mainly as a result of acquisition of Infantas Oriente 3D seismic in La Cira Infantas.

1Q23 capex and exploration expenditures totalled $29.2 million.

Adjusted EBITDAX and Free Cash Flow

$ million	1Q23	4Q22	1Q22	Δ q/q	Δ y/y
Net income for the period	75.8	45.6	86.6	66%	-13%
Financial income and financial expenses	8.8	8.9	8.8	-1%	–%
Depreciation, depletion and amortisation	32.0	32.2	29.6	–%	8%
Income tax expense	48.2	70.1	46.2	-31%	4%
Exploration expenses and dry hole cost	2.5	6.8	18.9	-64%	-87%
Foreign exchange (income) / loss	6.9	(3.3)	6.1	nm	13%
Accretion of decommissioning liability	1.0	(0.4)	1.6	nm	-37%
Prepaid expenses and bond cost amortisation	3.3	2.8	3.0	17%	8%
Property, plant and equipment retirement	–	7.2	(0.3)	-100%	-100%
Inventory impairment	0.0	(1.3)	0.1	-100%	-100%
Unrealised fair value gain on derivatives	(0.4)	(0.7)	16.2	-37%	nm
Inventory fluctuation	(5.2)	(0.6)	(1.4)	800%	285%
Other income	–	0.2	–	-100%	–%
Fair value remeasurements	–	(1.4)	3.9	-100%	-100%
Other non-cash items	–	4.5	–	-100%	–%
Adjusted EBITDAX[6]	172.8	170.5	219.4	1%	-21%
Exploration drilling(1)	(0.1)	(14.5)	(9.6)	-99%	-99%
Exploration and seismic expense	(2.1)	(1.8)	(0.8)	12%	165%
Tax payments	(18.2)	–	(19.4)	–%	-6%
Capital expenditures(1)	(27.0)	(60.8)	(27.9)	-56%	-3%
Decommissioning funding	–	(2.3)	–	-100%	–%
Change in working capital(2)	(66.5)	28.7	(32.5)	nm	104%
Non-recurring costs	–	(1.5)	–	-100%	–%
Realised FX rate gain (loss)	4.5	(4.5)	0.7	nm	553%
Lease payments	(0.6)	(0.5)	(1.3)	4%	-57%
Free Cash Flow	62.8	113.3	128.6	-45%	-51%

(1) Figures including capital accruals | (2) Figures excluding capital accruals

[6] 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 reviewed strategy for the Group, from 1Q23 we now present the Teca result within Adjusted EBITDAX. Prior quarters have been revised to reflect this.

Net income increased 66% q/q mainly due to a lower deferred income tax expense of $21.9 million given a reduced expected taxable income in a lower price environment in 1Q23, $14.8 million from better operational performance (increase in volumes sold by $8.4 million, and reduced operating expenses and SG&A by $6.4 million) and others ($14.1 million[7]), partially offset by a lower realised price ($20.6 million).

Change in working capital in 1Q23 is mainly explained by a significant reduction in accounts payable from $194.9 million to $124.3 million[8] (excluding capital accruals).

Adjusted EBITDAX for 1Q23 was $172.8 million, resulting in an Operating netback of $56.4/boe. Adjusted EBITDAX increased 1% q/q despite a decrease of $6.5/bbl in Brent. Free Cash Flow totalled $62.8 million before the Oxy contingent payment of $45.0 million during the quarter.

Cash Flows

The table presents our primary sources and uses of cash and cash equivalents for 1Q23 and 1Q22:

$ million	1Q23	1Q22
Net cash flows from operating activities	82.1	134.1
Net cash flows used in investing activities	(61.2)	(59.2)
Net cash flows from financing activities	(9.3)	(15.0)
Increase in cash and cash equivalents during the period	11.7	59.8
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	(2.6)	(0.7)
Cash and cash equivalents at the end of the period	115.2	178.4

Cash flows from operating activities for 1Q23 of $82.1 million is presented net of cash taxes paid of $18.2 million. Cash flows used in investing activities include cash additions of $18.6 million to PPE and $0.1 million to exploration and evaluation assets, financial income of $2.6 million, and the contingent payment to Oxy of $45.0 million. Cash flows from financing activities include dividends paid to non-controlling interest of $8.8 million, and lease payments of $0.6 million.

Cash and cash equivalents at quarter-end were $115.2 million.

Liquidity and Capital Resources

$ million (unless stated)	1Q23	1Q22
2028 senior notes @ 6%	600.0	600.0
Capital lease obligations	6.1	5.1
Total indebtedness	606.1	605.1
Net debt	490.8	426.7
LTM Adjusted EBITDAX	767.5	687.4
Net leverage (x)	0.6x	0.6x
Cash and cash equivalents	115.2	178.4
Undrawn amounts of committed credit lines[9]	83.1	61.8
Total liquidity	198.4	240.2

We ended 1Q23 with an ample liquidity, closing at $198.4 million, and maintaining a low net leverage at 0.6x.

[7] Includes inventory fluctuation ($4.6 million), changes in impairments ($5.8 million) and other expenses (net) ($3.7 million).
[8] See note 20 of the condensed consolidated financial statements for the period ended 31 March 2023
[9] Includes the RCF and the short-term credit line as of 31 March 2023. The original amount of the RCF was $80.0 million of which 37.5% is peso-denominated. As of 31 March 2023, the available amount of the RCF reflects the COP/USD exchange rate as of that date and $11.1 million used towards letters of credit. After quarter-end, the aggregate principal amount of commitments provided under the RCF increased to $120.0 million.

During the quarter, an additional $20 million short-term credit line was secured to support working capital requirements. The full amount was drawn down and received on 3 April, after quarter-end, taking advantage of lower interest rates vs the RCF.

After quarter-end, some lenders increased their commitments under the RCF by $40 million. The aggregate principal amount of commitments provided under the RCF is now $120.0 million[10].

Summary of quarterly results

	1Q23	4Q22	3Q22	2Q22	1Q22	4Q21	3Q21	2Q21
Production & sales (kboed)								
Gross production	83.2	81.4	80.1	78.4	85.8	83.6	78.8	84.3
SBR production[11]	44.6	44.2	43.5	42.8	46.7	45.1	41.6	44.1
Net production	34.9	33.0	32.1	31.2	35.4	34.3	31.6	34.7
Net sales	34.0	32.1	30.3	30.9	35.0	34.8	30.3	36.7
Operating netback per barrel of net sales ($/boe)								
Brent price	82.1	88.6	97.7	112.0	97.9	79.7	73.2	69.1
Realised price	74.2	81.3	92.6	103.8	90.7	70.2	63.9	65.0
Lifting cost	(14.8)	(16.5)	(16.8)	(13.9)	(12.8)	(14.0)	(15.1)	(12.1)
Transport cost	(0.7)	(0.8)	(0.9)	(0.9)	(0.8)	(0.4)	(0.4)	(0.6)
Adjusted operating netback per boe[9]	58.6	64.0	74.9	89.0	77.1	55.8	48.4	52.3
Administrative expenses	(3.3)	(4.4)	(1.9)	(3.3)	(3.3)	(3.8)	(2.1)	(4.6)
Realised loss on derivatives	(0.4)	(0.3)	(1.0)	(10.0)	(5.6)	(2.4)	(0.4)	(0.7)
Other[12]	1.4	(1.6)	1.9	2.0	1.4	3.4	(2.0)	5.8
Operating netback[9]	56.4	57.7	73.9	77.7	69.6	53.0	43.9	52.8
Adjusted EBITDAX ($ million)								
Total revenue	227.3	240.2	258.2	291.8	286.0	224.7	178.2	216.9
Lifting cost	(45.4)	(48.7)	(46.8)	(38.9)	(40.4)	(45.0)	(42.2)	(40.3)
Transport cost	(2.2)	(2.5)	(2.5)	(2.6)	(2.6)	(1.4)	(1.0)	(1.9)
Adjusted operating netback[9]	179.7	189.0	208.9	250.3	242.9	178.3	135.0	174.7
Administrative expenses	(10.1)	(12.9)	(5.3)	(9.2)	(10.2)	(12.1)	(5.9)	(15.3)
Realised loss on derivatives	(1.2)	(1.0)	(2.8)	(28.2)	(17.5)	(7.8)	(1.0)	(2.4)
Other[10]	4.4	(4.7)	5.0	5.6	4.2	11.1	(5.6)	19.1
Adjusted EBITDAX[9]	172.8	170.5	205.8	218.5	219.4	169.6	122.4	176.1
Supplementary financial results ($ million)								
Net income	75.8	45.6	80.9	85.6	86.6	84.9	45.6	(23.3)
Capex and exploration expenditures[9]	29.2	78.5	55.3	32.8	38.3	61.8	43.1	40.5
Free Cash Flow[9]	62.8	113.3	130.5	29.3	128.6	142.2	29.4	95.1
Cash & cash equivalents	115.2	106.2	302.5	189.8	178.4	119.3	261.1	233.0
Net debt[9]	490.8	494.8	300.7	414.4	426.7	488.4	347.8	372.2

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 reviewed strategy for the Group, from 1Q23 we now present the Teca result within Adjusted EBITDAX. Prior quarters have been revised to reflect this.

[10] The updated amount of the RCF is $120.0 million of which 25% is Colombian peso-denominated at the issuance rate of COP$ 3700/USD.
[11] See "Non-IFRS Measures" section.
[12] Other includes prepaid expenses, other income/expenses (net), realised foreign exchange gain (loss) and non-recurring costs.

Risk Management Contracts

Brent hedging programme

Our commodity hedging program 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.

As of the date of this document, for the period of 1Q23-3Q23 we had hedged 50% of our production, with a weighted average long put strike price of $63.7/bbl. The following table shows the percentage of hedged volumes and weighted average long put strike price per quarter:

	1Q23	2Q23	3Q23	1Q23-3Q23
Hedged volumes in long puts (%)	50%	50%	50%	50%
Weighted average strike ($/bbl)	62.8	63.1	65.0	63.7

Some of our long put positions include short puts. The following table shows the percentage of hedged volumes and weighted average short put strike price per quarter:

	1Q23	2Q23	3Q23	1Q23-3Q23
Hedged volumes in short puts (%)	12%	16%	50%	26%
Weighted average strike ($/bbl)	50.0	50.0	46.7	47.8

To remove put spread floors, we entered into new zero-collar options over 37% of our hedgeable production, with a weighted average short call strike price of $120.2/bbl for 1H23. We have not entered into call positions in 3Q23.

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

Currency hedging programme

During the quarter, we entered into currency hedging positions to manage volatility in the foreign exchange rate of Colombian peso to US dollar. As of the date of this document, for 1H23 we had hedging positions for a total of $148 million.

The following table shows zero-cost collar options of our current programme:

	1Q23	2Q23	1Q23-2Q23
Hedged volumes ($ million)	$4	$79	$83
Weighted average call strike (COP/USD)	4,963	5,084	5,078
Weighted average put strike (COP/USD)	4,833	4,807	4,808

The following table shows forwards of our current programme:

	1Q23	2Q23	1Q23-2Q23
Hedged volumes ($ million)	–	$65	$65
Average forward (COP/USD)	–	4,673	4,673

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 of dry hole costs and impairments).

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 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).

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 unaudited condensed consolidated financial statements for the period ended 31 March 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 license 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 license 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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