



SierraCol
energy

Management Discussion and Analysis ("MD&A") 1Q25

Source: SierraCol Energy Limited photo bank

This management discussion and analysis ("MD&A") of the financial condition and results of operations of SierraCol Energy Limited and its subsidiaries ("we", "our", "SierraCol", "SCE" or the "Company") should be read in conjunction with the interim consolidated financial statements for the period ended 31 March 2025 and 2024 and the notes thereto. Please read the full cautionary statements at the end of the document.

1Q25 performance highlights

Operational

Operational update

- Share Before Royalties ("SBR") production reached 45.9 kboed. Quarter on quarter, SBR production was 2% lower, mainly due to reduced output in the Caño Limón area following the implementation of temporary production control procedures in late March. These were prompted by restricted availability of the Bicentenario pipeline ("OBC") and the unavailability of the Caño Limón-Coveñas pipeline ("CLC") at the end of the quarter.
- Two rigs were active during the quarter, drilling and completing three new wells in the Caño Limón area and two in La Cira Infantas. The workover programme included 26 interventions across all operational areas.
- Year on year, production remained flat. Higher volumes from La Cira Infantas and output from the 2024 acquired assets in Central Llanos offset the lower output from Caño Limón area.

Driving impact: Our ESG commitment in action

- SierraCol released its fifth [Sustainability Report](#), reaffirming its commitment to transparency and responsible operations. The 2024 report showcases meaningful progress across ESG dimensions, strengthening the Company's position as a long-term value creator and sustainability leader in the global energy sector.
- SierraCol achieved a 58% reduction in net CO₂e emissions from legacy assets vs. 2020 baseline, reinforcing our decarbonisation efforts.
- SierraCol achieved ISO 50001:2019 certification in May 2025, advancing energy efficiency, cost reduction, and decarbonisation goals, while further aligning operational excellence with the Company's ESG commitments.

Financial

Financial metrics

- The realised oil price averaged \$70.1/bbl in 1Q25, up \$4.6/bbl q/q, primarily driven by a narrower Vasconia differential of \$2.7/bbl and a \$1.0/bbl improvement in the Brent benchmark.
- Net sales averaged 37.0 kboed in 1Q25, down 11% vs. 4Q24, mainly due to temporary pipeline constraints that led to deferred deliveries and higher quarter-end inventories, up by 212 kbo compared to the previous quarter.
- Adjusted operating netback stood at \$50.2/bbl.
- For 1Q25, Adjusted EBITDAX amounted to \$151.9 million, compared to \$180.5 million in the prior quarter.
- The Adjusted EBITDAX margin stood at 65% in 1Q25, compared to 72% in 4Q24. The variation primarily reflects lower realised revenue, with a \$31.7 million impact from reduced sales volume. This was partially offset by a favourable price effect of \$15.1 million and a \$7.3 million reduction in operating expenses. In addition, the margin was affected by lower realised foreign exchange gains compared to the previous quarter, with a \$19.5 million impact.
- Capital and exploration expenditures totalled \$33.1 million for the quarter.
- Free Cash Flow for the quarter reached \$74.4 million, supported by an adjusted EBITDAX of \$151.9 million. Key cash uses during the period included \$36.5 million in tax payments, \$29.3 million in capital expenditures, and a \$10.0 million dividend distributed to the holder of the non-controlling interest, prior to the acquisition of the remaining 25% interest in SierraCol Energy Arauca LLC ("Arauca"), which was completed on 28 February 2025.

Ample liquidity and low net leverage

- Total available liquidity stood at \$252.6 million, comprising cash and cash equivalents of \$135.9 million plus \$116.7 million from the Revolving Credit Facility ("RCF"). Throughout 1Q25 and as at the date of this document, the RCF remains fully available.
- In 1Q25, as part of the acquisition mentioned above, the Company entered into a new \$40.0 million long-term loan agreement with Banco Davivienda ("Davivienda"). The full amount was disbursed in

February 2025, with maturity scheduled two years from the disbursement date.

- Net debt amounted to \$636.4 million, including \$135.9 million in cash and cash equivalents, resulting in a net leverage ratio of 0.9x.

Risk Management

- Under the Brent hedging programme, the Company has hedged 40% of hedgeable production through September 2025, utilising long put options with a weighted average strike price of \$60.7/bbl. Additionally, we have hedged volumes for 4Q25 totalling 270,000 barrels, with an average strike price of \$60/bbl. The structure excludes caps, thereby preserving full upside exposure to oil prices.
- As part of the currency risk management strategy, FX hedges totalling \$108.0 million have been executed through 4Q25, using zero-cost collars with a weighted average strike range of COP 4,182/4,847 to cover operational requirements in Colombian pesos. In addition, forward contracts amounting to \$42.0 million have been secured mainly for tax payments, with a weighted average strike price of COP 4,409 for 2Q25.

Business Update

- As part of the relinquishment process of the Company's interest in the TECA Collaboration Contract executed with Ecopetrol, approvals have been obtained from both the Superintendency of Industry and Commerce ("SIC") and the National Hydrocarbons Agency ("ANH"). All remaining activities required to complete the relinquishment process were met, and completion was achieved on 30 April 2025.

Subsequent Events

- Since the end of the first quarter, the availability of the OBC pipeline has been restricted. As of the date of this note, availability has been restored, and production is being normalised.
- In May, Fitch Ratings affirmed SierraCol's credit rating at B+ with a stable outlook.

Performance Overview

Financial & Operational Results

	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
<u>Production & sales (kboed)</u>					
Gross production	83.5	85.8	82.7	-3%	1%
SBR production ⁽¹⁾	45.9	46.8	45.7	-2%	-%
Net production	39.1	39.9	38.1	-2%	3%
Net sales	37.0	41.5	35.7	-11%	4%
<u>Operating netback per barrel of net sales (\$/boe)</u>					
Brent price	75.0	74.0	81.8	1%	-8%
Realised price	70.0	65.4	76.1	7%	-8%
Lifting cost	(19.6)	(18.6)	(16.9)	5%	16%
Transport cost	(0.2)	(0.5)	(0.8)	-67%	-80%
Adjusted operating netback per boe ⁽¹⁾	50.2	46.3	58.4	8%	-14%
Administrative expenses	(3.4)	(3.2)	(2.6)	5%	31%
Realised loss on oil derivatives	(0.6)	(0.6)	(0.6)	0%	3%
Other ⁽²⁾	(0.6)	4.8	0.4	nm	nm
Operating netback ⁽¹⁾	45.7	47.3	55.6	-3%	-18%
<u>Adjusted EBITDAX (\$ million)</u>					
Total revenue	232.7	249.5	247.2	-7%	-6%
Lifting cost	(65.1)	(71.0)	(55.0)	-8%	18%
Transport cost	(0.5)	(1.9)	(2.7)	-71%	-79%
Adjusted operating netback ⁽¹⁾	167.1	176.6	189.6	-5%	-12%
Administrative expenses	(11.3)	(12.3)	(8.4)	-8%	34%
Realised loss on oil derivatives	(2.1)	(2.4)	(2.0)	-12%	5%
Other ⁽²⁾	(1.9)	18.4	1.3	nm	nm
Adjusted EBITDAX ⁽¹⁾	151.9	180.3	180.5	-16%	-16%
Adjusted EBITDAX margin (%) ⁽¹⁾	65%	72%	73%	-10%	-11%
<u>Key financial results (\$ million)</u>					
Net income	54.9	33.2	75.2	65%	-27%
Capex and exploration expenditures ⁽¹⁾	33.1	54.8	36.7	-40%	-10%
Free Cash Flow ⁽¹⁾	74.4	97.7	9.3	-24%	700%
Cash & cash equivalents	135.9	90.8	110.8	50%	23%
Net debt ⁽¹⁾	636.4	640.1	528.7	-1%	20%

⁽¹⁾ See "Non-IFRS Measures" section. | ⁽²⁾ Other includes realised foreign exchange gain (loss) and other income/expenses (net).

Production and sales

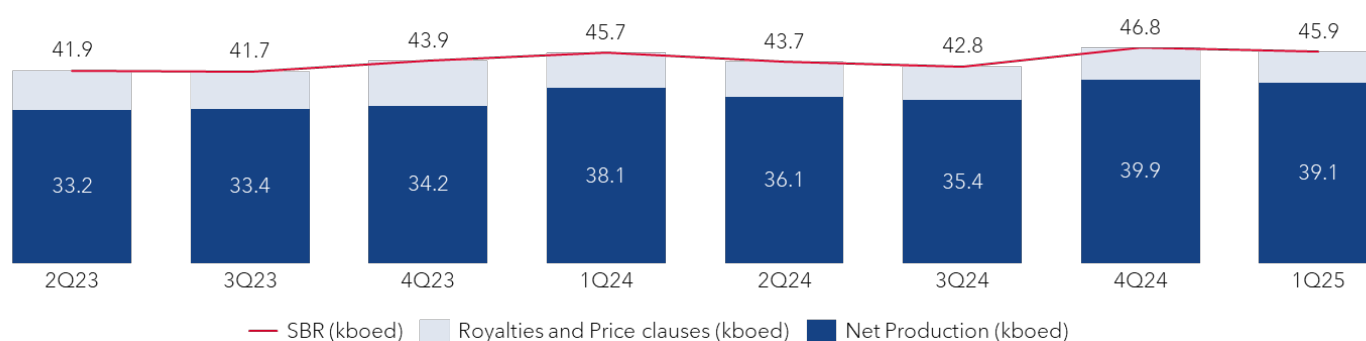
kboed	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
Gross production	83.5	85.8	82.7	-3%	1%
<u>SBR production</u>					
Caño Limón area	25.6	26.3	29.2	-3%	-12%
Middle Magdalena	13.2	13.4	13.0	-1%	2%
Central Llanos ⁽¹⁾	7.1	7.1	3.6	-%	99%
SBR production	45.9	46.8	45.7	-2%	-%
Light and medium oil	45.2	46.0	45.0	-2%	-%
Heavy oil	0.5	0.4	0.5	18%	7%
Gas	0.2	0.3	0.2	-13%	-%
Royalties in kind	4.0	4.0	4.0	1%	-%
Price-related effects	2.8	2.8	3.7	-%	-22%
Net production	39.1	39.9	38.1	-2%	3%
Net sales	37.0	41.5	35.7	-11%	4%

⁽¹⁾ Central Llanos production incorporates volumes from the 2024 acquired assets, starting 6 August 2024.

Share Before Royalties (“SBR”) production for 1Q25 was 45.9 kboed. Quarter on quarter, SBR production was 2% lower, mainly due to reduced output in the Caño Limón area, following the implementation of temporary production control procedures in late March. These were prompted by restricted availability of the OBC pipeline and the unavailability of the CLC pipeline at the end of the quarter.

Year on year, production was essentially flat. Stronger performance in the Middle Magdalena basin, combined with increased contributions from the 2024 acquired assets in the Central Llanos area, offset by lower production of high-rate wells drilled in 1Q24 in the Caño Limón area, and the impact of temporary production controls implemented as described above.

During the quarter, two active rigs drilled and completed three new wells in the Caño Limón area and two new wells in La Cira Infantas. The workover programme included 22 interventions in the Caño Limón area, one in La Cira Infantas, and three in the Central Llanos area. The latter marks the restart of the development efforts in a previously underinvested field, integrated into the Company’s asset portfolio last year.



Crude oil inventory

kbo	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
Beginning of the period	499	289	172	73%	190%
Oil production	3,498	3,644	3,446	-4%	2%
Oil sales	(3,307)	(3,791)	(3,229)	-13%	2%
Crude oil in transit ⁽¹⁾	22	357	99	-94%	-78%
End of the period	711	499	488	42%	46%
% of period production	20%	14%	14%		

⁽¹⁾ Includes other adjustments

Approximately 95% of the crude oil inventory at the end of 1Q25 corresponded to volumes from the Caño Limón area. Inventory increased by 42% quarter-over-quarter, from 499 kbo to 711 kbo, driven by lower sales from this area due to limited pipeline availability during the period.

Revenue

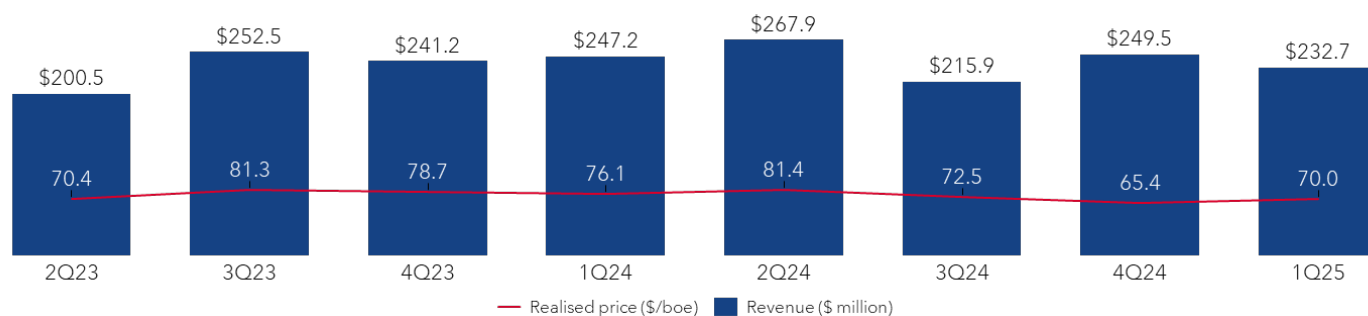
	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
<u>Revenue (\$ million)</u>					
Oil sales	232.0	248.6	246.5	-7%	-6%
Natural gas sales	0.6	0.6	0.5	-8%	7%
Services	0.1	0.3	0.2	-48%	-31%
Total revenue	232.7	249.5	247.2	-7%	-6%
<u>Net sales (million boe)</u>					
Oil sales	3.3	3.8	3.2	-13%	2%
Natural gas sales	0.02	0.02	0.02	-14%	2%
Net sales	3.3	3.8	3.2	-13%	2%
<u>Realised price rollforward (\$/bbl)</u>					
Brent	75.0	74.0	81.8	1%	-8%
Vasconia differential	2.3	5.0	5.1	-55%	-55%
OBC contractual differential (tariff-based)	1.5	1.5	0.5	-5%	211%
Central Llanos contractual differential (tariff-based)	0.8	1.3	0.6	-36%	27%
Other differential / (premium)	0.5	0.8	(0.5)	-39%	nm
Average realised price	70.0	65.4	76.1	7%	-8%

Revenue from oil sales amounted to \$232.7 million in 1Q25, reflecting a q/q decrease of \$16.6 million. The variance was primarily attributable to lower sales volumes, with an estimated impact of \$31.7 million. This was partially offset by a \$9.1 million positive contribution from a narrower Vasconia differential, and a \$6.1 million increase related to the Brent benchmark, following a \$1.0/bbl improvement.

The average realised price increased by \$4.5/bbl versus 4Q24, mainly driven by a \$2.7/bbl improvement in the Vasconia differential and the aforementioned increase in Brent.

Compared to 1Q24, revenue declined 6% (\$14.5 million), largely due to a \$29.7 million impact from a lower average realised price. This effect was partially offset by a \$9.2 million benefit from the Vasconia differential and a \$6.0 million increase from higher sales volumes.

The average realised price decreased by \$6.2/bbl y/y, primarily reflecting a \$6.8/bbl decline in the Brent benchmark and wider commercial differentials, mainly driven by increased volumes shipped through the OBC pipeline. These effects were partially offset by a \$2.8/bbl improvement in the Vasconia differential.



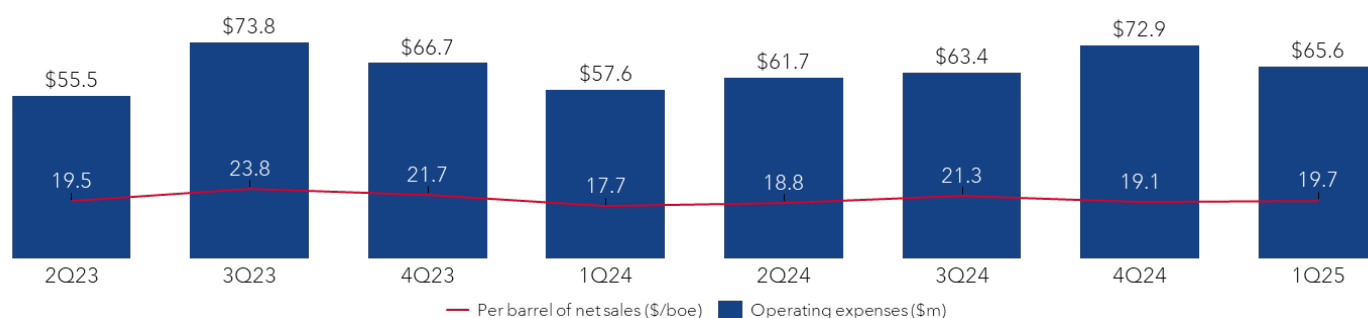
Operating expenses

\$ million (unless otherwise stated)	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
Lifting cost	65.1	71.0	55.0	-8%	18%
Transport cost	0.5	1.9	2.7	-71%	-79%
Operating expenses	65.6	72.9	57.6	-10%	14%
Per barrel of net sales (\$/boe)	19.7	19.1	17.7	3%	11%

Compared to 4Q24, lifting cost decreased by \$5.9 million mainly due to: i) \$8.4 million in timing effects related to planned maintenance activities and the execution of the social responsibility programme in 4Q24, ii) \$2.6 million reduction in well intervention activity in Central Llanos area, aligned with the Company's cost-efficiency programme. These savings were partially offset by a \$3.1 million increase due to inflation on services and materials, and a \$2.0 million impact from the 4% revaluation of the Colombian peso (\$4,191 USD/COP in 1Q25 vs \$4,348 in 4Q24).

Compared to 1Q24, lifting cost increased by 18%, mainly due to \$8.5 million associated with the incorporation of the 2024 acquired assets, and a \$1.4 million increase due to higher electricity purchased from the national grid and increased well interventions activity in La Cira Infantas.

Transport cost decreased by \$1.4 million q/q and \$2.1 million y/y, primarily due to lower evacuation volumes through the CLC pipeline, which has been unavailable since 22 August 2024. Transported Caño Limón area volumes were 0% in 1Q25, compared to 0% in 4Q24 and 72% in 1Q24.

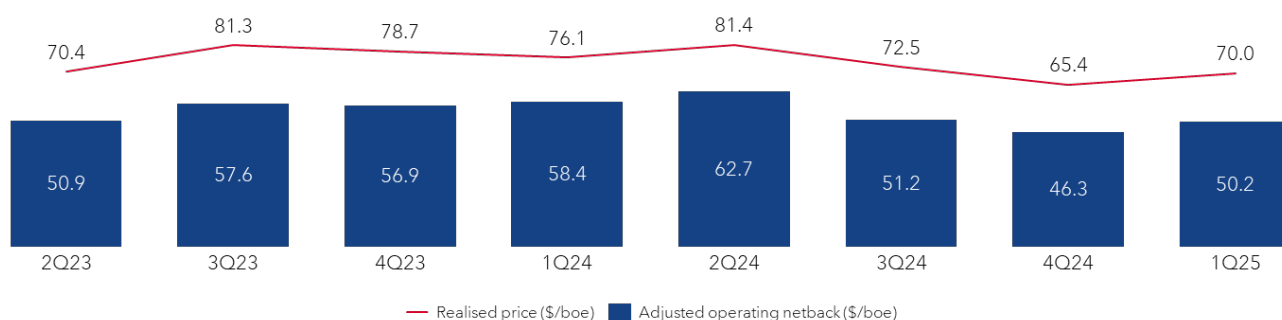


Adjusted operating netback per boe

\$/boe of net sales	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
Brent price	75.0	74.0	81.8	1%	-8%
Realised price	70.0	65.4	76.1	7%	-8%
Lifting cost	(19.6)	(18.6)	(16.9)	5%	16%
Transport cost	(0.2)	(0.5)	(0.8)	-67%	-80%
Adj. operating netback per boe	50.2	46.3	58.4	8%	-14%

The adjusted operating netback per boe increased by 8% q/q, reaching \$50.2/boe in 1Q25, primarily driven by a 7% improvement in the realised price.

On a y/y basis, the adjusted operating netback declined by 14%, reflecting an 8% decrease in the realised price and a 16% increase in lifting costs, as detailed in the previous section.



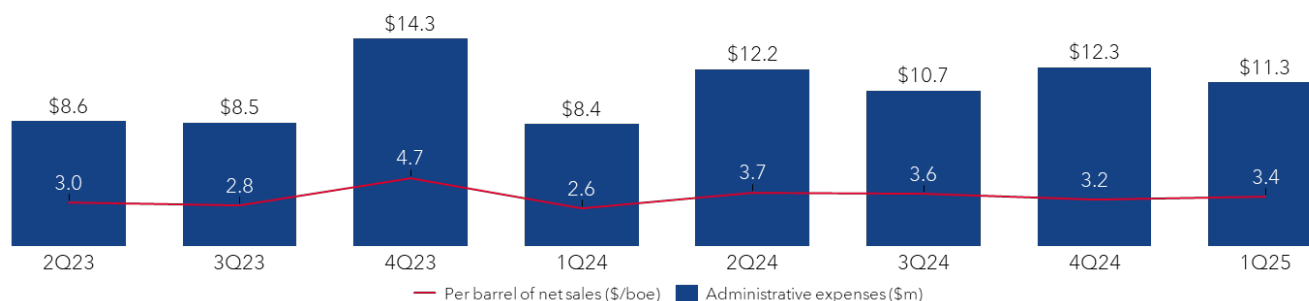
Administrative expenses

\$ million	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
Administrative expenses	11.0	11.7	7.4	-6%	48%
One-off ⁽¹⁾	0.3	0.6	1.0	-46%	-69%
Administrative expenses	11.3	12.3	8.4	-8%	34%
Per barrel of net sales (\$/boe)	3.4	3.2	2.6	5%	31%

⁽¹⁾ One-off expenses include M&A transaction costs, as well as costs associated with special projects and other unusual transactions.

Total administrative expenses were \$11.3 million in 1Q25, down \$1.0 million (8%) versus 4Q24, mainly due to the revaluation of the Colombian peso (COP 4,348/USD in 4Q24 vs COP 4,191/USD in 1Q25) and higher partner cost-recoveries. Recurring administrative expenses were \$11.0 million, down 6% q/q.

Compared to 1Q24, administrative expenses increased by \$2.9 million, primarily due to the timing of annual compensation adjustments, which were executed in 1Q25 versus 2Q24 in the prior year, and higher cost associated with the integration of the assets acquired in 2024.



Capital and exploration expenditures

\$ million	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
Caño Limón area	18.7	25.7	13.6	-27%	38%
Middle Magdalena	6.9	15.3	13.2	-55%	-48%
Central Llanos	0.6	4.7	0.2	-87%	186%
Development capex	26.2	45.6	27.0	-43%	-3%
Exploratory drilling	5.8	8.1	8.9	-29%	-35%
Total capex	32.0	53.7	36.0	-40%	-11%
Exploration expenses ⁽¹⁾	1.1	1.1	0.7	8%	59%
Capital and exploration expenditures	33.1	54.8	36.7	-40%	-10%

⁽¹⁾ Exploratory expenses are presented net of dry hole costs and impairments.

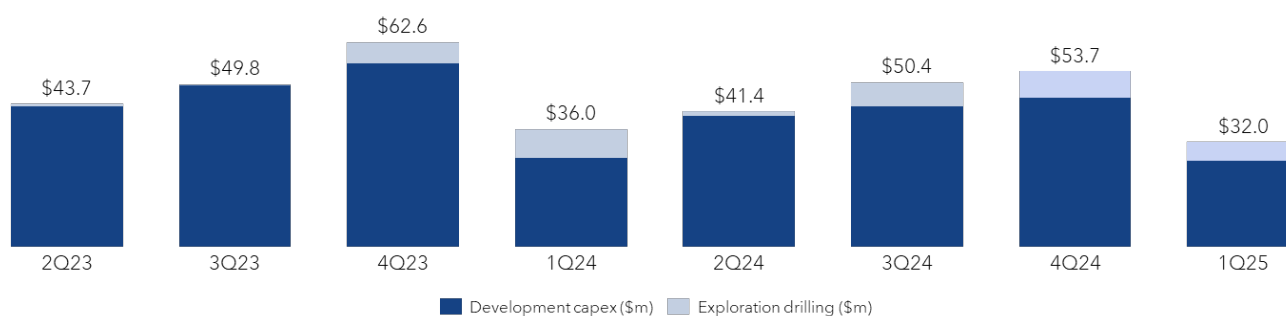
Capital and exploration expenditures totalled \$33.1 million in 1Q25, reflecting a planned reduction in activity following the execution peak observed in 4Q24.

Development capex amounted to \$26.2 million, down 43% q/q. This decrease reflects the seasonally lower execution in the first quarter of the year, reduced drilling and workover activity in the Middle Magdalena basin, and slower progress in facilities projects across all areas. During the quarter, five development wells were drilled and completed (three in the Caño Limón area and two in Middle Magdalena), compared to twelve wells in 4Q24. In addition, 26 workovers were performed, down from 32 in the prior quarter.

Compared to 1Q24, development capex declined by \$0.8 million. The reduction is explained by a later start of the drilling programme in Middle Magdalena in 2025 (mid-February), whereas in 1Q24, operations continued from the previous year. This was partially offset by increased activity in the Caño Limón area. In 1Q24, 18 development wells were drilled and completed (1 in Caño Limón area and 17 wells in Middle Magdalena), and 27 workovers were executed.

Exploratory drilling expenditures reached \$5.8 million in 1Q25, down \$2.3 million q/q. Although one well was drilled in each quarter, 4Q24 included greater civil works advancement in Putumayo and a successful exploration result in Caño Limón area. Year over year, exploratory drilling decreased by \$3.2 million, reflecting lower well complexity in 1Q25 relative to the 1Q24 results.

Capital and exploration expenditures totalled \$33.1 million in the first quarter of 2025.



Adjusted EBITDAX and Free Cash Flow

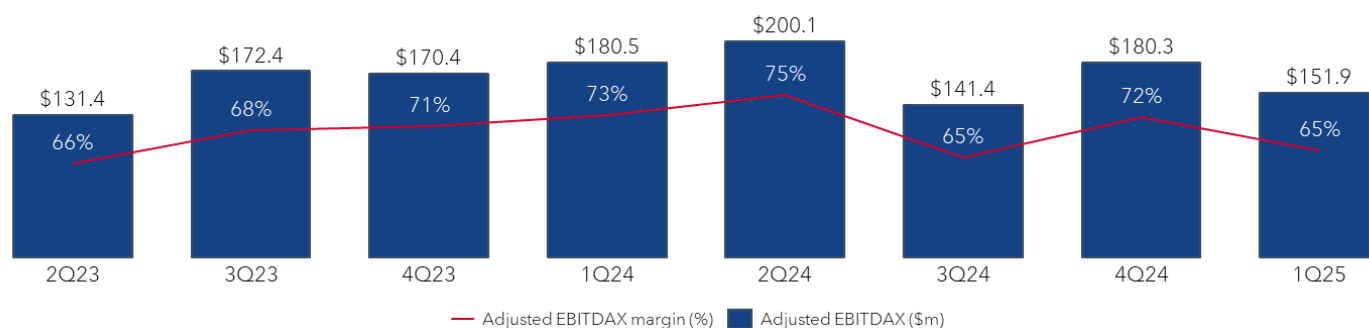
\$ million	1Q25	4Q24	1Q24	Δ q/q	Δ y/y
Total comprehensive income	54.9	32.7	75.2	68%	-27%
Financial income and financial expenses	10.9	8.1	9.0	35%	21%
Depreciation, depletion and amortisation	37.4	37.6	34.0	-1%	10%
Income tax expense	52.5	83.0	59.2	-37%	-11%
Exploration expenses and dry hole cost	1.2	1.2	6.8	–%	-83%
Unrealised foreign exchange (gain) / loss	(2.8)	23.2	(1.0)	nm	173%
Accretion of decommissioning liability	1.1	1.7	0.8	-34%	36%
Debt cost amortisation	0.9	(4.2)	1.3	nm	-34%
Unrealised fair value gain on derivatives	0.1	1.2	3.8	-88%	-96%
Inventory fluctuation	(4.3)	(5.9)	(8.6)	-27%	-50%
Fair value remeasurements	–	0.5	–	-100%	–%
Other non-cash items	(0.2)	1.1	–	nm	–%
Non-recurring costs	0.3	0.3	–	1%	–%
Adjusted EBITDAX	151.9	180.3	180.5	-16%	-16%
Exploration drilling ⁽¹⁾	(5.8)	(8.1)	(8.9)	-29%	-35%
Exploration and seismic expense ⁽²⁾	(1.1)	(1.1)	(0.7)	8%	59%
Capital expenditures ⁽¹⁾	(29.3)	(45.6)	(27.0)	-36%	8%
Tax payments	(36.5)	(33.2)	(42.7)	10%	-15%
Inventory of capitalizable parts/components	–	3.8	0.4	-100%	-100%
Release of abandonment trusts	16.5	–	–	–%	–%
Decommissioning funding	–	(0.1)	–	-98%	–%
Change in working capital ⁽³⁾	(20.7)	46.9	(95.5)	nm	-78%
Non-recurring costs	(0.3)	(0.3)	–	1%	–%
Realised foreign exchange gain / (loss)	–	(44.8)	3.4	-100%	-100%
Lease payments	(0.2)	(0.2)	(0.2)	18%	26%
Free Cash Flow	74.4	97.7	9.3	-24%	700%

⁽¹⁾ Figures including capital and exploration drilling accruals | ⁽²⁾ Exploratory expenses are presented net of dry hole costs and impairments | ⁽³⁾ Figures excluding capital and exploration drilling accruals.

Adjusted EBITDAX for 1Q25 reached \$151.9 million, reflecting a 16% decrease q/q. The decline was primarily driven by a 7% decline in sales volume and reduced FX gains compared to the previous quarter. This was partially offset by an 8% reduction in lifting costs. On a unit basis, the operating netback stood at \$45.7/boe.

Free Cash Flow totalled \$74.4 million in 1Q25, after tax payments of \$36.5 million and capital and exploration expenditures of \$33.1 million.

Tax payments decreased by \$6.3 million y/y, mainly due to a lower first income tax instalment in 1Q25. This reflects the lower taxable income generated in 2023, compared to 2022, resulting in a reduced tax payment.



Cash flows

The table summarises the classification of our cash flows for 1Q25 and 1Q24:

\$ million	1Q25	1Q24
Net cash flows from operating activities	83.7	35.5
Net cash flows used in investing activities	(6.7)	(23.6)
Net cash flows from financing activities	(34.0)	10.6
Increase in cash and cash equivalents during the period	43.0	22.6
Cash and cash equivalents at the beginning of the period	90.8	88.7
Effect of foreign exchange on cash and cash equivalents held in foreign currencies	2.2	(0.5)
Cash and cash equivalents at the end of the period	135.9	110.8

As presented in the interim condensed consolidated statement of cash flows, net cash provided by operating activities totalled \$83.7 million in 1Q25, after income tax payments of \$36.5 million.

Cash flows used in investing activities included \$20.1 million related to additions to property, plant and equipment ("PPE"), and \$5.5 million for exploration and evaluation assets. These outflows were partially offset by the release of abandonment funds amounting to \$16.5 million, along with financial income of \$2.3 million.

Cash flows used in financing activities totalled \$34.0 million, primarily reflecting the \$60.3 million acquisition of non-controlling interests, a \$10.0 million dividend payment to then holder of the non-controlling interest, and \$3.5 million in interest and financial expenses. These outflows were partially offset by a \$40.0 million disbursement under a new long-term debt loan.

As a result, cash and cash equivalents at the end of the period stood at \$135.9 million.

Liquidity and capital resources

The table below shows our total liquidity balance as of 31 March 2025 and 2024:

\$ million (unless stated)	31 March 2025	31 March 2024
RCF	120.0	120.0
Short-term credit lines	50.0	25.0
Total committed credit lines	170.0	145.0
Drawn amount of the RCF	–	(13.0)
Drawn amount of short-term credit lines	(50.0)	(20.0)
Total drawn amounts of committed credit lines	(50.0)	(33.0)
COP devaluation effect ⁽¹⁾	(3.3)	(0.9)
Available amount of committed credit lines	116.7	111.1
Cash and cash equivalents	135.9	110.8
Total liquidity	252.6	221.9

⁽¹⁾ 25% of the current aggregate principal amount under the RCF is peso-denominated.

The following table shows total indebtedness, net debt and net leverage as of 31 March 2025 and 2024:

\$ million (unless stated)	31 March 2025	31 March 2024
2028 senior notes @ 6.00%	600.0	600.0
RCF	–	13.0
Bancolombia loan	74.0	–
BTG loan	50.0	20.0
Davivienda loan	40.0	–
Capital lease obligations	8.3	6.5
Total indebtedness	772.3	639.5
(-) Cash & cash equivalents	135.9	110.8
(=) Net debt	636.4	528.7
LTM Adjusted EBITDAX	673.7	654.7
Net leverage (x)	0.9x	0.8x

We ended 1Q25 with ample liquidity, closing at \$252.6 million, while maintaining a low net leverage ratio of 0.9x.

Revolving Credit Facility: SCE and SierraCol Energy Andina ("Andina"), a wholly owned subsidiary of SCE, entered into a revolving facility in June 2021, amended in April 2023 to increase the principal amount in US dollars (tranche B). The facility expires in June 2026. The following table shows the current commitments:

\$ million (unless stated)	Amount	Rate
USD tranche A	50.0	SOFR+ 4.6%
COP tranche A ⁽¹⁾	30.0	IBR+ 4.5%
USD tranche B	40.0	SOFR+ 5.1%
Total RCF	120.0	
COP devaluation effect	(3.3)	
Total Available	116.7	

⁽¹⁾ Equivalent to COP \$111,914 million at the time of execution of the RCF.

Bancolombia loan: In March 2024, Cedco entered into a \$74.0 million loan. Key terms of the agreement include an unsecured bilateral loan maturing in June 2027. The loan follows an amortising schedule with a two-year grace period and quarterly interest payments at a rate of SOFR3M + 3.0%.

BTG short-term loan: In December 2024, Andina obtained a \$50.0 million unsecured short-term loan to support working capital requirements. The loan follows a bullet structure, maturing in December 2025, with monthly interest payments at a rate of SOFR1M + 3.25%.

Davivienda loan: In February 2025, Holder entered into a new \$40.0 million unsecured loan with a 24-month bullet structure and semi-annual interest payments at a rate of SOFR6M + 2.2%.

Quarterly Financial and Operational Overview⁽¹⁾

	1Q25	4Q24	3Q24	2Q24	1Q24	4Q23	3Q23	2Q23
<u>Production & sales (kboed)</u>								
Gross production	83.5	85.8	77.2	79.6	82.7	80.0	77.1	77.9
SBR production ⁽²⁾	45.9	46.8	42.8	43.7	45.7	43.9	41.7	41.9
Net production	39.1	39.9	35.4	36.1	38.1	34.2	33.4	33.2
Net sales	37.0	41.5	32.4	36.2	35.7	33.3	33.7	31.3
<u>Operating netback per barrel of net sales (\$/boe)</u>								
Brent price	75.0	74.0	78.7	85.0	81.8	82.9	85.9	77.7
Realised price	70.0	65.4	72.5	81.4	76.1	78.7	81.3	70.4
Lifting cost	(19.6)	(18.6)	(20.5)	(17.7)	(16.9)	(20.6)	(22.8)	(18.9)
Transport cost	(0.2)	(0.5)	(0.8)	(1.1)	(0.8)	(1.1)	(1.0)	(0.6)
Adjusted operating netback per boe ⁽²⁾	50.2	46.3	51.2	62.7	58.4	56.9	57.6	50.9
Administrative expenses	(3.4)	(3.2)	(3.6)	(3.7)	(2.6)	(4.7)	(2.8)	(3.0)
Realised loss on oil derivatives	(0.6)	(0.6)	(0.8)	(0.6)	(0.6)	(0.4)	(0.5)	(0.5)
Other ⁽³⁾	(0.6)	4.8	0.6	2.4	0.4	3.7	1.2	(1.3)
Operating netback ⁽²⁾	45.7	47.3	47.5	60.8	55.6	55.6	55.6	46.1
<u>Adjusted EBITDAX (\$ million)</u>								
Total revenue	232.7	249.5	215.9	267.9	247.2	241.2	252.5	200.5
Lifting cost	(65.1)	(71.0)	(61.1)	(58.2)	(55.0)	(63.2)	(70.7)	(53.9)
Transport cost	(0.5)	(1.9)	(2.3)	(3.5)	(2.7)	(3.5)	(3.1)	(1.6)
Adjusted operating netback ⁽²⁾	167.1	176.6	152.5	206.2	189.6	174.5	178.7	144.9
Administrative expenses	(11.3)	(12.3)	(10.7)	(12.2)	(8.4)	(14.3)	(8.5)	(8.6)
Realised loss on oil derivatives	(2.1)	(2.4)	(2.3)	(2.0)	(2.0)	(1.3)	(1.5)	(1.3)
Other ⁽³⁾	(1.9)	18.4	1.9	8.1	1.3	11.5	3.7	(3.6)
Adjusted EBITDAX ⁽²⁾	151.9	180.3	141.4	200.1	180.5	170.4	172.4	131.4
Adjusted EBITDAX margin (%) ⁽²⁾	65%	72%	65%	75%	73%	71%	68%	66%
<u>Key financial results (\$ million)</u>								
Net income	54.9	32.7	58.3	67.0	75.2	88.4	76.8	56.6
Capex and exploration expenditures ⁽²⁾	33.1	54.8	51.5	42.3	36.7	63.9	50.8	44.5
Free Cash Flow ⁽²⁾	74.4	97.7	71.2	64.0	9.3	133.0	(34.2)	129.9
Cash & cash equivalents	135.9	90.8	180.3	120.2	110.8	88.7	107.3	173.2
Net debt ⁽²⁾	636.4	640.1	500.8	511.2	528.7	538.0	539.5	497.8

⁽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⁾ See "Non-IFRS Measures" section. | ⁽³⁾ Other includes realised foreign exchange gain (loss) and other income/expenses (net).

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 in advance.

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	2Q25	Brent	1,384,254	61.0
Put	3Q25	Brent	1,370,285	60.4
Put	4Q25	Brent	270,000	60.0

This results in hedging positions for 40% of our hedgeable production until September 2025, with a weighted average long put strike price of \$60.7/bbl. Additionally we have hedged 4Q25 volumes, totalling 270,000 barrels with an average put strike price of \$60/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 currency hedging positions to manage volatility in the foreign exchange rate of Colombian peso to US dollar for \$108 million 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	2Q25	COP / USD	\$36.0	4,150 / 4,808	–
	3Q25	COP / USD	\$15.0	4,220 / 4,893	–
	4Q25	COP / USD	\$15.0	4,220 / 4,893	–
Forward	2Q25	COP / USD	\$42.0	–	4,409.0

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 EBITDAX margin: calculated as Adjusted EBITDAX divided by total revenue.

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 the additions to oil and gas assets, buildings and administrative assets, and exploration assets, plus exploration expenses, excluding dry hole expenses.

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.

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.

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 (“SierraCol”, “we,” “our”, “SCE” or the “Company”) should be read in conjunction with the interim consolidated financial statements for the period ended 31 March 2025 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.

