Management Discussion and Analysis 4Q25 and FY25

SierraCol energy

MORNINGSTAR Sustainalytics **Industry** ESG Leader 2026

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 condensed consolidated financial statements for the period ended 31 December 2025 and 2024 and the notes thereto. Please read the full cautionary statements at the end of the document.

FY2025 and 4Q25 performance highlights

Operational

Operational update

- FY25 SBR production averaged 42.0 kboed, down 6% y/y, primarily due to temporary production restrictions in the Caño Limón area during 2Q25 following limited pipeline availability. This was partially offset by higher production from the Central Llanos area following the 2024 asset acquisitions.
- 4Q25 SBR production was 41.2 kboed, 3% lower q/q, mainly due to temporary failures of high-potential wells and unplanned electrical events in the Caño Limón area. These issues have been addressed, and production has been restored, with YTD SBR production at 42.5 kboed.
- Compared to 4Q24, production was 12% lower, mainly due to: i) temporary failures of high-potential wells, unplanned electrical events and stabilised production performance following elevated initial production rate from wells drilled during 4Q24 in the Caño Limón area, ii) lower activity levels in La Cira Infantas in 2025 compared to 2024, and iii) the exit of the Teca asset in 2Q25.
- During the year, 55 wells were drilled and completed, and 125 workovers were executed across the portfolio. During the quarter, two active rigs drilled and completed 6 new wells. The workover programme included 44 interventions.

Strong 2P reserves replacement: 109%

- Achieved a 109% 2P Reserves Replacement Ratio ("RRR"), marking the ninth consecutive year of exceeding 100% replacement ratio. Delivered a 91% 1P RRR.
- Reported 2P reserves of 129 million boe and 1P reserves of 88 million boe, maintaining a stable reserves life with Reserves-to-Production ("R/P") ratios of 9.8 and 6.7 years, respectively.

Guidance 2026

- SBR production estimated at 41 - 44 kboed.
- Capital and exploration expenditures estimated at $130 - $170 million.

Driving sustainability and safety excellence

- The Company currently ranks 5th among 282 companies in the oil and gas sector in Sustainalytics' ESG Risk Rating, making it a top-ranked operator with the lowest ESG risk level.
- At SierraCol, we have reduced our CO_2e emissions by 60% compared to the baseline year of 2020.
- In 4Q25, we installed gas-to-liquids plants at the Caño Limón area main production facilities, achieving a 35% reduction in emissions from these sources and an additional average production of 800 boe fully stabilized.
- Achieved a Total Recordable Incident Rate ("TRIR") of 0.30 in 2025, a 9.1% improvement from 2024, continuing a downward trend since 2019. This marks the lowest level recorded in the past five years.

Financial

Financial metrics

- FY25 average realised price was $64.5/bbl, 12% lower than prior year, reflecting the trend in Brent benchmark.
- Revenue from oil sales totalled $849.5 million in FY25, representing a 13% y/y decrease, primarily driven by a lower Brent benchmark price (impact of $153.9 million). This was partially offset by an improvement in the Vasconia differential, which contributed a $32.5 million benefit.
- For FY25, Adjusted EBITDAX amounted to $498.1 million, compared with $702.4 million in the prior year. The year-over-year variation was primarily attributable to lower price realisations of $121.3 million as a result of a lower Brent benchmark price, partially offset by an improvement in the Vasconia differential. The remaining variance mainly reflects higher operating costs of $29.8 million, driven by a $20 million increase in the Central Llanos area following the asset acquisitions in August 2024, and $9.8 million attributable to inflation on services and materials. The variance also reflects lower income from the currency hedging programme ($17 million) and realised foreign exchange losses ($22 million) primarily related to the Colombian peso currency exposure of accounts payable and tax payments.
- FY25 reported an adjusted EBITDAX margin of 58%.
- In 4Q25, Adjusted EBITDAX was $89.6 million, a decrease of $49.9 million q/q. This performance

reflected lower realised prices ($58.8/bbl in 4Q25 64.2/bbl in 3Q25), with an impact of $18.9 million, together with higher operating expenses of $7.6 million. Additionally, lower sales volumes reduced results by $19.0 million during the quarter.

- The 4Q25 Adjusted EBITDAX margin stood at 47%, while the Adjusted Operating netback reached $34.6/boe.
- For the full year, capital and exploration expenditures totalled $185.3 million. 72% of the total annual investment was allocated to development capex was allocated to the drilling and completion of new wells, as well as to the workover campaign across all areas.
- Free Cash Flow for the year reached $172.1 million, supported by an Adjusted EBITDAX of $498.1 million, after deducting primarily capital and exploration expenditures of $185.3 million, tax payments of $167.7million, and $33.1 million in changes in working capital. Free Cash Flow for the quarter amounted to $94.1 million.

Liquidity and net leverage

- Total available liquidity stood at $310.6 million, comprising $160.6 million in cash and cash equivalents and $150.0 million available under the RCF credit line, which remained fully available as of the reporting date.
- In November 2025, the Company, through its subsidiaries SierraCol Energy Andina LLC (“Andina”), SierraCol Energy Arauca LLC (“Arauca”) , and Colombia Energy Development Co (“Cedco”), as co-issuers, issued senior notes due 2030 in an aggregate principal amount of $650 million. Net proceeds from the issuance were used to: tender $300 million of the Company’s existing senior notes due 2028, fund an extraordinary dividend of $321.8 million, reduce other existing indebtedness of the Company and partially fund related transaction costs and expenses.
- During 4Q25, the Davivienda loan was partially repaid by $22 million, leaving an outstanding balance of $18 million. In addition, the RCF was amended to (i) increase the size of the facility from $120 million to $150 million; (ii) denominate the entire facility in U.S. dollars, (iii) set the interest rate at SOFR + 4.5%, (iv) replace a lender, and (v) extend the maturity date to May 2028.
- Ordinary dividends of $58.2 million were paid to the shareholders from cash flows generated by ordinary operating activities.
- Net debt closed at $934.7 million, resulting in a net leverage ratio of 1.88x.

Risk management

- *Brent hedging programme:* 60% of net production is hedged through June 2026 using a combination of long put options with a weighted-average strike price of $55.2/bbl and premium collars with a weighted-average put strike price of $55.5/bbl and call strike price of $80/bbl. For July and August, SCE hedged 40% of its net production and 10% of September volumes through long put options with a weighted-average strike price of $58/bbl, as well as premium collars with a weighted-average put strike price of $56.5/bbl and call strike price of $80/bbl.
- *Currency hedging programme:* FX hedges for $30 million through 1H26 were executed using forwards with weighted-average forward exchange rates of COP 3,711.24 for March, COP 3,736.59 for April and COP 3,765.30 for May to cover peso-denominated outflows.

Subsequent Events

- On 27 January 2026, the Company declared and paid an ordinary dividend of $50 million related to 2025 financial and operating performance.
- After year-end 2025, The Carlyle Group ("Carlyle") and Prime Infrastructure Capital, Inc ("Prime Infra") entered into an agreement by which Carlyle will sell to Prime Infra the totality of its shares in SierraCol Energy Limited. The transaction is subject to customary regulatory approvals.

Performance Overview

Financial & Operational Results

	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Production & sales (kboed)								
Gross production	74.9	77.5	85.8	-3%	-13%	76.4	81.3	-6%
SBR production[1]	41.2	42.5	46.8	-3%	-12%	42.0	44.8	-6%
Net production	35.7	36.5	39.9	-2%	-10%	36.0	37.3	-4%
Net sales	35.4	38.5	41.5	-8%	-15%	36.3	36.4	–%
Exchange rate (1USD/COP)	3,818.9	4,004.4	4,347.1	-5%	-12%	4,052.7	4,071.3	–%
Operating netback per barrel of net sales ($/boe)								
Brent price	63.1	68.2	74.0	-7%	-15%	68.2	79.9	-15%
Realised price	58.8	64.2	65.4	-8%	-10%	64.5	73.6	-12%
Total lifting cost	(23.1)	(19.2)	(18.6)	21%	24%	(20.7)	(18.4)	13%
Transport and marketing costs	(1.0)	(0.8)	(0.5)	23%	108%	(0.8)	(0.8)	2%
Adjusted operating netback per boe[1]	34.6	44.2	46.3	-22%	-25%	42.9	54.4	-21%
General and administrative expenses	(6.2)	(3.0)	(3.2)	109%	94%	(3.9)	(3.3)	18%
Premiums and realised fair value on derivatives	(0.6)	(0.6)	(0.6)	0%	-5%	(0.6)	(0.7)	-6%
Other[2]	(0.3)	(1.3)	1.3	-78%	nm	(0.9)	2.2	nm
Operating netback[1]	27.5	39.3	43.7	-30%	-37%	37.6	52.7	-29%
Adjusted operating breakeven	28.4	24.0	27.7	19%	3%	25.2	25.5	-1%
Operating breakeven	35.5	28.8	30.3	23%	17%	30.6	27.2	13%
Adjusted EBITDAX ($ million)								
Total revenue	191.2	227.7	249.5	-16%	-23%	854.6	980.6	-13%
Total lifting cost	(75.2)	(68.0)	(71.0)	11%	6%	(275.0)	(245.3)	12%
Transport and marketing costs	(3.4)	(3.0)	(1.9)	13%	77%	(10.4)	(10.3)	1%
Adjusted operating netback[1]	112.7	156.8	176.6	-28%	-36%	569.2	725.0	-21%
General and administrative expenses	(20.2)	(10.6)	(12.3)	92%	65%	(51.1)	(43.5)	17%
Premiums and realised fair value on derivatives	(1.9)	(2.1)	(2.4)	-5%	-19%	(8.2)	(8.7)	-6%
Other[2]	(0.9)	(4.6)	4.8	-80%	nm	(11.8)	29.6	nm
Adjusted EBITDAX[1]	89.6	139.5	166.7	-36%	-46%	498.1	702.4	-29%
Adjusted EBITDAX margin (%)[1]	47%	61%	67%	-24%	-30%	58%	72%	-19%
Key financial results ($ million)								
Net income	4.0	66.2	33.2	-94%	-88%	182.7	233.8	-22%
Capital and exploration expenditures[1]	62.9	47.0	54.8	34%	15%	185.3	185.2	–%
Free Cash Flow[1]	94.1	70.8	123.8	33%	-24%	172.1	265.0	-35%
Cash & cash equivalents	160.6	148.6	90.8	8%	77%	160.6	90.8	77%
Net debt[1]	934.7	618.3	640.1	51%	46%	934.7	640.1	46%

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

2025 year-end reserves audit results

SierraCol's reserves are presented on a working interest basis after royalties and are derived from the annual independent reserves evaluation certified by DeGolyer and McNaughton ("D&M") as at 31 December 2025, prepared in accordance with the Petroleum Resources Management System ("PRMS").

Certified 2P reserves total 129 million boe, of which 99% is oil, representing a reserves life index (R/P) of 9.8 years. For FY25, SierraCol achieved a 2P reserves replacement ratio (RRR) of 109%, achieving a nine-year track record of 2P RRR above 100% and effectively maintaining the reserves life compared with 2024 (9.7 years).

Certified 1P reserves amount to 88 million boe, corresponding to an R/P ratio of 6.7 years and a reserves replacement ratio of 91%.

	PDP Proved developed producing	PD Proved developed	1P Proved reserves	2P Proved plus probable	3P Proved plus probable plus possible
million boe	64	77	88	129	157
R/P ratio (years)	4.9	5.8	6.7	9.8	12.0

- 88% of SierraCol's 1P reserves are proved developed (PD) reserves.
- 68% of SierraCol's 2P reserves are proved (1P) reserves.

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

	1P	2P
million boe		
31 December 2024	88.8	127.9
Production	-13.1	-13.1
Net additions	12.0	14.4
31 December 2025	87.6	129.2
R/P (years)	6.7	9.8
RRR (%)	91%	109%

The following table provides an overview of SCE's 1P and 2P reserves as of 31 December 2025 by area:

	2025		2024	
	1P	2P	1P	2P
million boe				
Caño Limón area	25.2	38.8	25.7	39.3
Middle Magdalena	52.2	68.0	52.5	67.6
Central Llanos	10.2	22.4	10.6	21.0
Total	87.6	129.2	88.8	127.9

The following table summarises the after-tax net present value discounted at 10% ("NPV10") for 1P and 2P reserves as at 31 December 2025:

	1P	2P
Reserves (million boe)	87.6	129.2
NPV10 after tax ($ million)	1,207	1,656

The following table presents the Brent price forecast used to estimate reserves and NPV10 in accordance with PRMS:

	2026	2027	2028	2029
Brent ($/bbl)	63.7	68.5	74.3	80.0

From 2030 onwards, prices and costs were escalated at 2% p.a.

2026 Guidance

The Company provides the following 2026 guidance:

	2026 guidance
SBR production (kboed)	41 - 44
Capital and exploration expenditures ($ million)	$130 – $170

Guidance includes development and exploration capex as well as exploration expenses.

Production and sales

kboed	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Gross production	74.9	77.5	85.8	-3%	-13%	76.4	81.3	-6%
SBR production								
Caño Limón area	22.1	23.0	26.3	-4%	-16%	22.3	26.8	-17%
Middle Magdalena	12.2	12.4	13.4	-1%	-9%	12.6	13.0	-3%
Central Llanos[(1)]	6.9	7.1	7.1	-2%	-2%	7.1	4.9	43%
SBR production	41.2	42.5	46.8	-3%	-12%	42.0	44.8	-6%
Light and medium oil	40.9	42.2	46.0	-3%	-11%	41.5	44.1	-6%
Heavy oil	–	–	0.4	nm	-100%	0.2	0.4	-60%
Gas	0.3	0.3	0.3	7%	14%	0.3	0.3	4%
Royalties in kind	3.6	3.7	4.0	-3%	-10%	3.7	3.9	-5%
Price-related effects	1.9	2.3	2.9	-16%	-35%	2.3	3.5	-33%
Net production	35.7	36.5	39.9	-2%	-10%	36.0	37.3	-4%
Net sales	35.4	38.5	41.5	-8%	-15%	36.3	36.4	–%

(1) Central Llanos production incorporates mainly volumes from Caracara field, starting 6 August 2024.

Production is presented as Share Before Royalties ("SBR") and the result for the period is as follows:

FY25 SBR production averaged 42.0 kboed, down 6% y/y, primarily due to temporary production restrictions in the Caño Limón area during 2Q25 following limited pipeline availability. This was partially offset by higher production from the Central Llanos area following the 2024 asset acquisitions.

4Q25 SBR production was 41.2 kboed, 3% lower q/q, mainly due to temporary failures of high-potential wells and unplanned electrical events in the Caño Limón area. These issues have been addressed, and production has been restored, with YTD SBR production at 42.5 kboed.

Compared to 4Q24, production was 12% lower, mainly due to: i) temporary failures of high-potential wells, unplanned electrical events and stabilised production performance following elevated initial production rate from wells drilled during 4Q24 in the Caño Limón area, ii) lower activity levels in La Cira Infantas in 2025 compared to 2024, and iii) the exit of the Teca asset in 2Q25.

The following table presents the new wells and workover programme for FY25 and 4Q25:

	FY25	4Q25
Wells drilled and completed		
Caño Limón area	10	1
Middle Magdalena	45	5
Central Llanos	–	–
Total	55	6
Workover programme		
Caño Limón area	91	35
Middle Magdalena	22	5
Central Llanos	12	4
Total	125	44

Crude oil inventory

kbo	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Beginning of the period	257	417	289	-38%	-11%	499	172	190%
Oil production	3,256	3,333	3,644	-2%	-11%	13,033	13,582	-4%
Oil sales	(3,227)	(3,521)	(3,791)	-8%	-15%	(13,163)	(13,246)	-1%
Crude oil in transit	(65)	28	357	nm	nm	(147)	(9)	>1000%
End of the period	222	257	499	-14%	-56%	222	499	-56%
% of period production	7%	8%	14%			2%	4%	

For FY25, crude oil inventory closed at 222 kbo, down 56%, compared with FY24, mainly reflecting sales volumes exceeding production during the period, supported by the successful implementation of evacuation initiatives in the Caño Limón area.

Revenue

	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Revenue ($ million)								
Oil sales	188.8	226.7	248.6	-17%	-24%	849.5	977.1	-13%
Natural gas sales	0.8	0.7	0.6	5%	25%	2.7	2.4	14%
Services	1.7	0.3	0.3	451%	501%	2.4	1.1	107%
Total revenue	191.2	227.7	249.5	-16%	-23%	854.6	980.6	-13%
Net sales (million boe)								
Oil sales	3.2	3.5	3.8	-8%	-15%	13.2	13.2	-1%
Natural gas sales	0.03	0.02	0.02	7%	18%	0.09	0.09	8%
Net sales	3.3	3.5	3.8	-8%	-15%	13.3	13.3	-1%
Realised price rollforward ($/boe)								
Brent	63.1	68.2	74.0	-7%	-15%	68.2	79.9	-15%
Vasconia differential	3.4	1.9	5.0	81%	-32%	2.3	4.8	-52%
OBC contractual differential[(1)]	1.5	1.6	1.5	-7%	-6%	1.3	0.6	115%
Central Llanos contractual differential[(1)]	0.8	1.4	0.5	-39%	53%	0.4	0.3	38%
Other differential / (premium)	(1.4)	(0.9)	1.5	62%	nm	(0.4)	0.6	nm
Average realised price	58.8	64.2	65.4	-8%	-10%	64.5	73.6	-12%

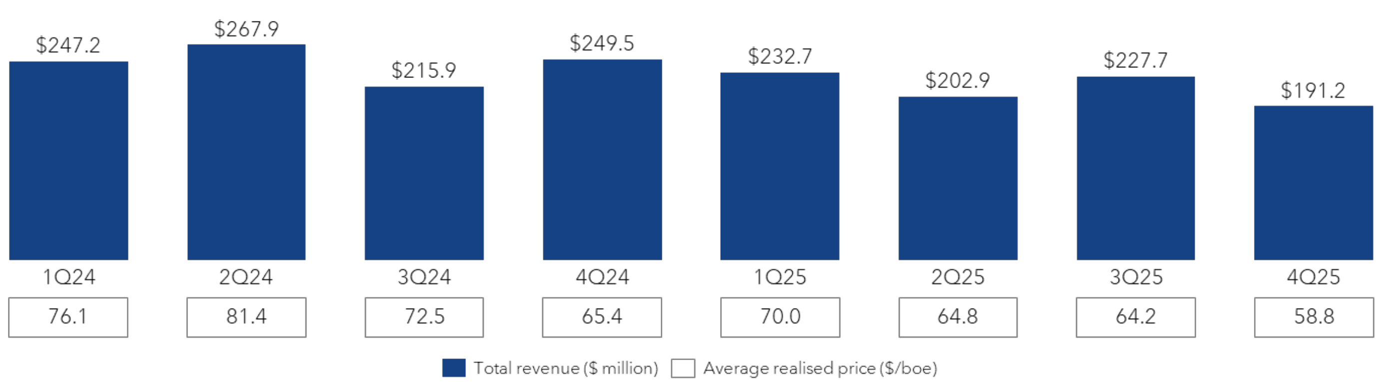
[(1)] Tariff-based

For FY25, revenue from oil sales totalled $849.5 million, a decrease of 13% ($127.6 million) compared with FY24. Performance was mainly influenced by a lower Brent benchmark which had an impact of $153.9 million. This effect was partially mitigated by a $2.5/bbl improvement in the Vasconia differential, contributing a $32.5 million benefit.

Compared to the previous quarter, 4Q25, revenue from oil sales amounted to $188.8 million, down $37.9 million q/q. This variation primarily reflected lower sales volumes, with an impact of ($19.0 million), together with a lower Brent price ($14.0 million) and a wider Vasconia differential ($4.9 million).

The average realised price declined by $5.4/boe q/q, mainly due to: i) a $5.1/bbl decrease in Brent price; and ii) a $1.5/bbl widening of the Vasconia differential.

Year on year, compared with 4Q24, revenue from oil sales decreased by 24% ($59.8 million), mainly driven by lower sales volumes ($37.0 million) and a lower realised price ($27.9 million). These effects were partially offset by an improvement in the Vasconia differential, which contributed with a $5.2 million benefit.



Operating expenses

$ million (unless otherwise stated)	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Total lifting cost	75.2	68.0	71.0	11%	6%	275.0	245.3	12%
Transport cost	1.5	0.7	1.9	107%	-22%	3.5	10.3	-66%
Catatumbo Tax(1)	1.9	2.3	–	-17%	nm	6.9	–	nm
Operating expenses	78.5	71.0	72.9	11%	8%	285.4	255.6	12%
Per barrel of net sales ($/boe)	24.1	20.0	19.1	21%	26%	21.5	19.2	12%

(1) Expense recognised as a marketing cost that relates to the new 1% tax on hydrocarbon sales (also referred to as "Catatumbo Tax"). This expense is temporary and will remain in effect until 31 December

In FY25, lifting costs increased by 12% y/y, mainly driven by: i) a $20 million increase in the Central Llanos area following the asset acquisitions in August 2024, ii) $13 million attributable to inflation of approximately 5% on services and materials. However, these increases were partially offset by energy efficiency measures and well work savings under the Company's cost efficiency programme.

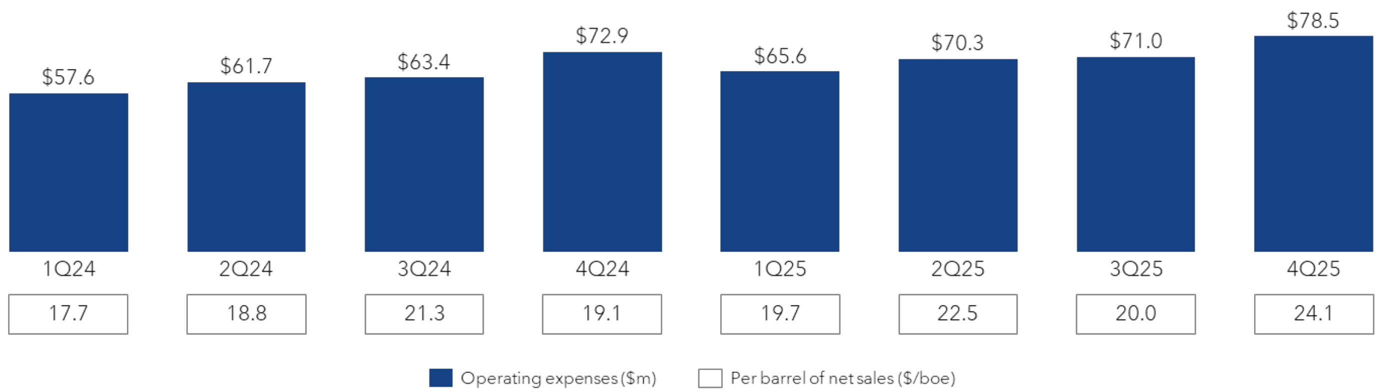
On a quarter on quarter basis, lifting costs rose by 11%, reflecting higher well work activity in Central Llanos area and social responsibility programme activities performed in 4Q25, as well as the appreciation of the Colombian peso ($3,818 USD/COP in 4Q25 compared with $4,003 USD/COP in 3Q25).

Year on year, lifting costs in 4Q25 were 6% higher, mainly driven by the appreciation of the Colombian peso ($3,818 USD/COP in 4Q25 versus $4,348 USD/COP in 4Q24) and inflation of approximately 5% on services and materials. In addition in 4Q25 was performed higher well work activity in Central Llanos area.

Starting in 2Q25, the temporary Catatumbo tax was recognised as a marketing cost and continued to be recorded as such through year-end 2025, when it expired.

During FY25, all Caño Limón area volumes were evacuated through the Bicentenario pipeline, compared with approximately 58% in FY24.

Operating costs per barrel averaged $21.5/boe in FY25, representing a 12% y/y increase.

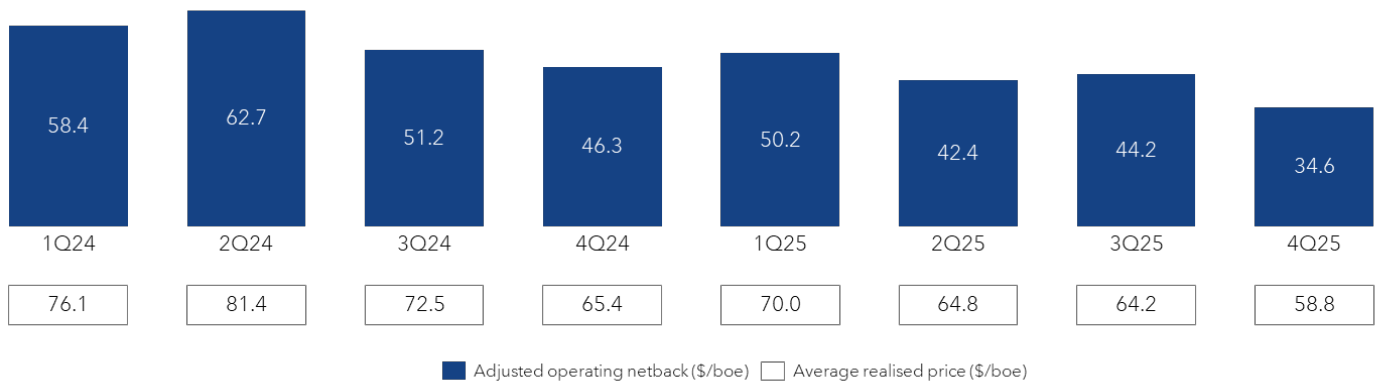


Adjusted operating netback per boe

$/boe of net sales	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Brent price	63.1	68.2	74.0	-7%	-15%	68.2	79.9	-15%
Realised price	58.8	64.2	65.4	-8%	-10%	64.5	73.6	-12%
Total lifting cost	(23.1)	(19.2)	(18.6)	21%	24%	(20.7)	(18.4)	13%
Transport cost	(0.5)	(0.2)	(0.5)	125%	-9%	(0.3)	(0.8)	-66%
Catatumbo tax	(0.6)	(0.6)	–	-9%	nm	(0.5)	–	nm
Adj. operating netback per boe	34.6	44.2	46.3	-22%	-25%	42.9	54.4	-21%

For FY25, adjusted operating netback per boe averaged $42.9/boe, a 21% y/y decrease, mainly reflecting lower realised prices and higher lifting costs.

In 4Q25, adjusted operating netback averaged $34.6/boe, down 22% q/q and 25% y/y, primarily influenced by a weaker Brent benchmark and higher lifting costs.



General and administrative expenses

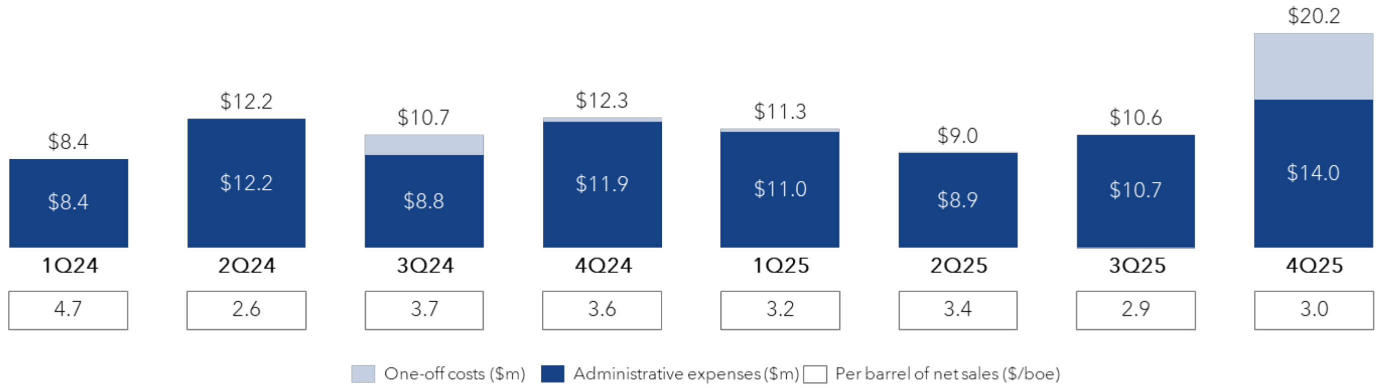
$ million (unless otherwise stated)	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
General and administrative expenses	14.0	10.7	11.9	32%	18%	44.6	41.3	8%
Special transactions and one-off costs	6.2	(0.1)	0.3	nm	nm	6.5	2.3	189%
General and administrative expenses	20.2	10.6	12.3	92%	65%	51.1	43.5	17%
Per barrel of net sales ($/boe)	6.2	3.0	3.2	109%	94%	3.9	3.3	18%

During FY25, general and administrative ("G&A") expenses, excluding special transactions and one-off costs, increased by $3.3 million y/y, primarily driven by higher personnel costs, including additional headcount in the Central Llanos area following the 2024 asset acquisitions, and higher execution of general services. These increases were partially offset by higher overhead recoveries from partners.

Special transactions and one-off costs mainly relate to fees and expenses incurred in connection with the amendment and extension of the Group's revolving credit facility.

In 4Q25, excluding special transactions and one-off costs, G&A expenses totalled $14.0 million, representing a 32% q/q increase compared to 3Q25, mainly reflecting higher professional fees and the appreciation of the Colombian peso ($3,819 USD/COP in 4Q25 compared with $4,004 USD/COP in 3Q25).

Year on year, excluding one-off items, G&A expenses in 4Q25 increased by $2.1 million compared with 4Q24, primarily driven by the appreciation of the Colombian peso ($3,819 USD/COP in 4Q25 versus $4,347 USD/COP in 4Q24).



Capital and exploration expenditures

$ million (unless otherwise stated)	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Caño Limón area	30.8	22.7	25.7	36%	20%	90.4	81.2	11%
Middle Magdalena	10.5	17.8	15.3	-41%	-32%	50.1	60.7	-18%
Central Llanos	10.2	3.0	4.7	238%	118%	16.4	13.7	19%
Development and maintenance capex	51.4	43.5	45.6	18%	13%	156.8	155.7	1%
Exploration drilling expenditures	9.8	2.7	8.1	271%	22%	24.2	25.8	-6%
Total capex	61.3	46.1	53.7	33%	14%	181.0	181.5	–%
Exploration expenses[1]	1.6	0.8	1.1	93%	52%	4.2	3.7	15%
Capital and exploration expenditures	62.9	47.0	54.8	34%	15%	185.3	185.2	–%

[1] Exploration expenses are presented net of dry hole costs and impairments.

Capital and exploration expenditures totalled $62.9 million in 4Q25 and $185.3 million in FY25, below the 2025 guidance range of $200 - $230 million.

Compared with FY24, FY25 development and maintenance capex was essentially unchanged at $156.8 million; although lower drilling activity (55 wells versus 76 in FY24), was compensated by a higher number of workovers (125 versus 88 in FY24).

In 4Q25, development and maintenance capex amounted to $51.4 million, an increase of 18% q/q, primarily due to higher workover activity in the Caño Limón area, as well as higher investments in facilities and maintenance projects across all areas. These effects were partially offset by a decrease in the drilling activity in Middle Magdalena area and by the 5% appreciation of the Colombian peso (average USD/COP 3,818 in 4Q25 versus USD/COP 4,003 in 3Q25).

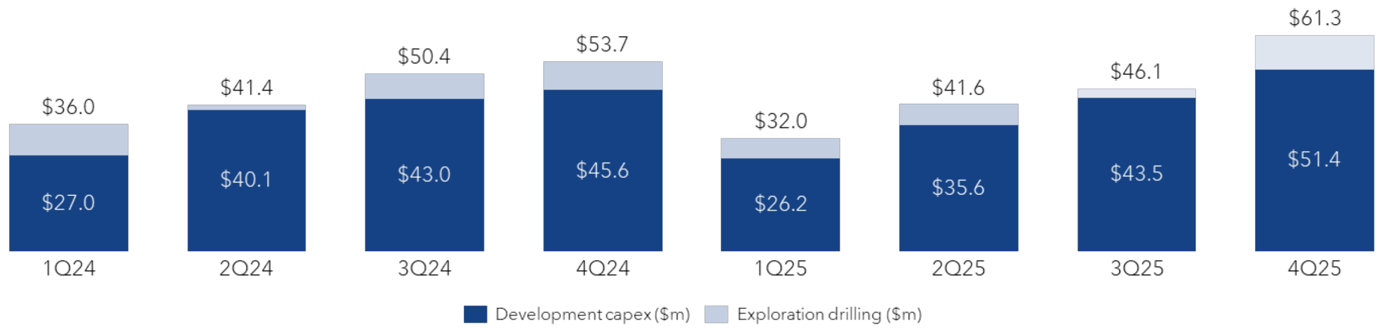
During the quarter, six development wells were drilled and completed (one in Caño Limón area and five in La Cira Infantas), compared to 26 in 3Q25. The workover programme consisted of 44 interventions compared to 25 interventions in 3Q25 , aligned with ongoing efforts to sustain production efficiency.

On a y/y basis, development and maintenance capex increased by $5.8 million in 4Q25, primarily due to a higher number of workovers (44 versus 32 in 4Q24),partially offset by a decrease in drilling activity in the Middle Magdalena, which was compensated by the receipt, in the last quarter of 2025, of advance materials for the Ramiriquí–Brincador well in the Central Llanos area.

For FY25, exploration drilling expenditures totalled $24.2 million, down 6% y/y or $1.5 million, mainly reflecting lower-cost wells drilled in the Putumayo and La Cira Infantas areas compared with higher-cost exploratory wells in Caño Limón area in FY24. Three exploratory wells were drilled in FY25 (one in Putumayo, one in Caño Limón and one in La Cira Infantas in Middle Magdalena), compared to two wells in Caño Limón area during FY24.

Exploration drilling expenditures amounted to $9.8 million in 4Q25, increasing 271% q/q, driven by the drilling of one exploratory well in the Middle Magdalena area, compared to no exploration wells drilled during 3Q25. Compared with 4Q24, exploration drilling expenditures increased by $1.7 million, mainly related to higher costs associated with the exploratory well drilled in 4Q25.

Exploration expenses, net of dry hole costs and impairments, amounted to $1.6 million in 4Q25 and $4.2 million in FY25, consistent with the level of evaluation activity and seismic reprocessing work carried out during the period.



Adjusted EBITDAX and Free Cash Flow

$ million (unless otherwise stated)	4Q25	3Q25	4Q24	Δ q/q	Δ y/y	FY25	FY24	Δ y/y
Total comprehensive income	4.0	66.2	32.7	-94%	-88%	182.7	233.2	-22%
Financial income and financial expenses	16.4	11.9	8.1	37%	103%	48.3	33.9	43%
Depreciation, depletion and amortisation	50.3	49.5	37.6	2%	34%	192.6	141.2	36%
Income tax expense	(51.0)	18.4	83.0	nm	nm	12.6	264.5	-95%
Exploration expenses	1.8	0.9	1.2	101%	53%	4.5	10.1	-56%
Unrealised foreign exchange (gain) / loss[(1)]	(4.4)	(11.5)	4.5	-61%	nm	(22.9)	23.8	nm
Accretion of decommissioning liability	–	1.4	1.7	nm	nm	3.8	4.8	-21%
Amortisation of debt issuance cost	5.1	1.0	0.9	399%	489%	7.9	3.0	163%
Unrealised fair value (gain) / loss on derivatives	(0.9)	0.9	1.2	nm	nm	(1.5)	1.1	nm
Inventory fluctuation	1.6	4.0	(5.9)	-61%	nm	8.7	(8.0)	nm
Impairment / (reversal) of PP&E[(2)]	41.0	–	(2.2)	–%	nm	40.9	(2.1)	nm
Write-off and impairment of E&E assets	16.6	–	0.1	>1000%	>1000%	16.7	6.4	160%
Other non-cash items	2.9	(3.3)	3.7	nm	-22%	(2.8)	(11.8)	-76%
Non-recurring costs	6.2	(0.1)	0.3	nm	>1000%	6.5	2.3	189%
Adjusted EBITDAX	89.6	139.5	166.7	-36%	-46%	498.1	702.4	-29%
Exploration drilling expenditures	(9.8)	(2.7)	(8.1)	271%	22%	(24.2)	(25.8)	-6%
Overhead and seismic expenses	(1.6)	(0.8)	(1.1)	93%	53%	(4.2)	(3.7)	15%
Development and maintenance capex	(51.4)	(43.5)	(45.6)	18%	13%	(156.8)	(155.7)	1%
Income tax payments	(6.3)	(7.2)	(5.2)	-12%	23%	(167.7)	(183.2)	-8%
Inventory of capitalisable parts	1.9	3.8	3.8	-50%	-50%	2.2	7.1	-70%
Acquisition of the Caracara and Llanos 22 contracts	–	–	2.7	–%	-100%	–	(58.4)	-100%
Decommissioning funding	(1.0)	–	(0.1)	–%	751%	(1.0)	(1.9)	-50%
Change in working capital[(3)]	79.2	(18.2)	13.8	nm	474%	33.1	(71.2)	nm
Non-recurring costs	(6.2)	0.1	(0.3)	nm	>1000%	(6.5)	(2.3)	189%
Lease payments	(0.2)	(0.2)	(0.2)	4%	40%	(0.8)	(0.7)	7%
Free Cash Flow	94.1	70.8	126.5	33%	-26%	172.1	206.6	-17%

[(1)] For 2024, this line has been adjusted to ensure consistency with the corresponding periods in 2025. [(2)] Following the annual impairment assessment, the Group recognised a non-cash impairment charge of $38.8 million in the LCI and Rio Verde CGUs, primarily driven by lower long-term oil price assumptions and updated production phasing (see Note 11 to the consolidated financial statements). [(3)] For the 2024 figures, the withholding tax paid in advance for the 2024 taxable year has been reclassified from changes in working capital to income tax payments, to ensure consistency with the presentation in the SCE 2024 Annual Report.

For FY25, adjusted EBITDAX amounted to $498.1 million, compared with $702.4 million in FY24, mainly reflecting lower realised prices and higher operating costs, partially mitigated by an improvement in the Vasconia differential.

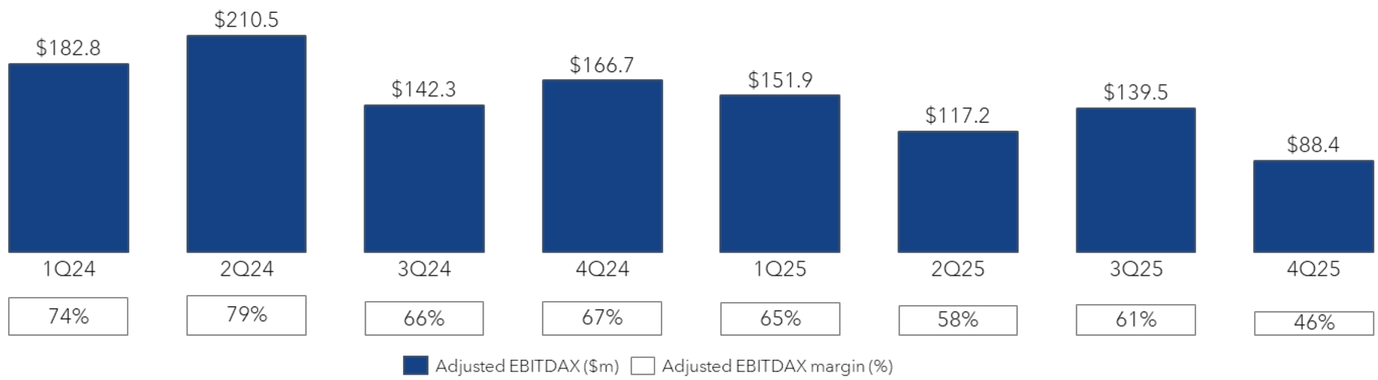
In 4Q25, adjusted EBITDAX totalled $89.6 million, representing a 36% q/q and 46% y/y decrease, primarily reflecting a weaker Brent benchmark, lower sales volumes and higher operating costs.

The adjusted EBITDAX margin decreased from 72% in FY24 to 58% in FY25, reflecting lower revenues and higher operating costs.

For FY25, Free Cash Flow totalled $172.1 million, compared with $206.6 million in FY24, mainly reflecting lower oil prices and higher operating costs.

Free Cash Flow amounted to $94.1 million in 4Q25, supported by advance collections received late in December 2025.

Key cash movements during the quarter included capital and exploration expenditures of $62.9 million, income tax payments of $6.3 million, and a $79.2 million increase in working capital, primarily driven by advance collections of $30 million received from partner and deferred supplier payments.



Cash flows

The table summarises the classification of our cash flows for FY25 and FY24:

$ million (unless otherwise stated)	FY25	FY24
Net cash flows from operating activities	342.4	410.3
Net cash flows (used) in investing activities	(126.3)	(237.3)
Net cash flows (used) in financing activities	(152.3)	(165.3)
Increase in cash and cash equivalents during the period	63.8	7.7
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	6.1	(5.6)
Cash and cash equivalents at the end of the period	160.6	90.8

Net cash generated from operating activities amounted to $342.4 million in FY25, after income tax payments of $167.7 million. This compares with $410.3 million in FY24, with the decrease primarily attributable to lower realised prices ($121.3 million), and higher operating costs ($29.8 million).

Net cash used in investing activities totalled $126.3 million, comprising $147.9 million in additions to property, plant and equipment ("PPE") and $21.6 million invested in exploration and evaluation activities. These outflows were partially offset by $34.0 million released from abandonment funds and $9.1 million in financial income.

Net cash used in financing activities amounted to $152.3 million, mainly reflecting a dividend payment of $390.0 million, the repayment of $300.0 million of senior notes due 2028, the $60.3 million acquisition of non-controlling interests, the repayment of the $50.0 million BTG short-term loan, $49.4 million in interest and other financial expenses, and $22.0million in repayments of the Davivienda loan. These outflows were partially offset by the issuance of $638.7 million of senior notes due 2030, together with new long-term loan disbursements of $40.0 million and $45.0 million from Davivienda and Banco de Bogotá, respectively.

Cash and cash equivalents at the end of the reported period stood at $160.6 million.

Liquidity and capital resources

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

$ million (unless otherwise stated)	31 December 2025	31 December 2024
RCF	150.0	120.0
Short-term credit lines	–	50.0
Total committed credit lines	150.0	170.0
Drawn amount of the RCF	–	–
Drawn amount of short-term credit lines	–	(50.0)
Total drawn amounts of committed credit lines	–	(50.0)
COP depreciation effect[1]	–	(4.6)
Available amount of committed credit lines	150.0	115.4
Cash and cash equivalents	160.6	90.8
Total available liquidity	310.6	206.1

[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 December 2025 and 2024:

$ million (unless otherwise stated)	31 December 2025	31 December 2024
2028 senior notes @ 6.00%	300.0	600.0
2030 senior notes @ 9.00%	650.0	–
BTG loan	–	50.0
Bancolombia (Panamá) S.A. loan	74.0	74.0
Banco de Bogotá S.A. loan	45.0	–
Banco Davivienda S.A. loan	18.0	–
Total lease liabilities	8.2	6.9
Total indebtedness	1,095.2	730.9
(-) Cash and cash equivalents	160.6	90.8
(=) Net debt	934.7	640.1
LTM Adjusted EBITDAX	498.1	702.4
Net leverage (x)	1.88x	0.91x

We ended FY25 with ample liquidity, closing at $310.6 million, while maintaining a net leverage ratio of 1.88x.

2030 Senior Notes: In November 2025, the Company, through its subsidiaries Arauca, Andina and Cedco, as co-issuers, issued senior notes due 2030 in an aggregate principal amount of $650 million, at a fixed annual rate of 9.00%, payable semi-annually in arrears in May and November and rank as senior unsecured debt.

2028 Senior Notes: Part of the net proceeds from the senior notes due 2030 was used to tender $300 million of the Company's senior notes due 2028, supporting the liability management strategy of the Company and a balanced debt maturity profile.

Revolving Credit Facility: SCE and Andina, a wholly owned subsidiary of SCE, entered into a revolving facility in June 2021. The facility was amended in April 2023 to increase the principal amount in U.S. dollars. Subsequently, in November 2025, the agreement was amended to (i) increase the available amount to $150 million, (ii) denominate the entire facility in U.S. dollars, (iii) set the interest rate at SOFR + 4.5%, and (iv) extend the maturity date to May 2028.

Bancolombia long-term 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%.

Banco de Bogotá long-term loan: In July 2025, Arauca entered into a $45.0 million unsecured promissory note with a 18-month bullet structure and semi-annual interest payments at a rate of SOFR6M + 2.55%.

Davivienda long-term loan: In February 2025, SierraCol Energy Holder entered into a $40.0 million unsecured loan with a 24-month bullet maturity and semi-annual interest payments at a rate of SOFR6M+ 2.20%. During 3Q25, the loan agreement was amended to transfer the borrower obligations to Arauca. On 22 December 2025, Arauca made a partial prepayment of $22 million, resulting in a remaining outstanding balance of $18 million.

Quarterly Financial and Operational Overview

	4Q25	3Q25	2Q25	1Q25	4Q24	3Q24	2Q24	1Q24
Production & sales (kboed)								
Gross production	74.9	77.5	69.7	83.5	85.8	77.2	79.6	82.7
SBR production[(2)]	41.2	42.5	38.4	45.9	46.8	42.8	43.7	45.7
Net production	35.7	36.5	32.6	39.1	39.9	35.4	36.1	38.1
Net sales	35.4	38.5	34.4	37.0	41.5	32.4	36.2	35.7
Exchange rate (1USD/COP)	3,818.9	4,004.4	4,199.1	4,193.2	4,347.1	4,094.0	3,926.0	3,915.0
Operating netback per barrel of net sales ($/boe)								
Brent price	63.1	68.2	66.7	75.0	74.0	78.7	85.0	81.8
Realised price	58.8	64.2	64.8	70.0	65.4	72.5	81.4	76.1
Total lifting cost	(23.1)	(19.2)	(21.4)	(19.6)	(18.6)	(20.5)	(17.7)	(16.9)
Transport and marketing costs	(1.0)	(0.8)	(1.1)	(0.2)	(0.5)	(0.8)	(1.1)	(0.8)
Adjusted operating netback per boe[(1)]	34.6	44.2	42.4	50.2	46.3	51.2	62.7	58.4
General and administrative expenses	(6.2)	(3.0)	(2.9)	(3.4)	(3.2)	(3.6)	(3.7)	(2.6)
Premiums and realised fair value on derivatives	(0.6)	(0.6)	(0.7)	(0.6)	(0.6)	(0.8)	(0.6)	(0.6)
Other[(2)]	(0.3)	(1.3)	(1.4)	(0.6)	1.3	0.9	5.6	1.1
Operating netback[(1)]	27.5	39.3	37.4	45.7	43.7	47.8	64.0	56.3
Adjusted operating breakeven	28.4	24.0	24.4	24.7	27.7	27.5	22.3	23.4
Operating breakeven	35.5	28.8	29.3	29.3	30.3	30.9	21.1	25.5
Adjusted EBITDAX ($ million)								
Total revenue	191.2	227.7	202.9	232.7	249.5	215.9	267.9	247.2
Total lifting cost	(75.2)	(68.0)	(66.8)	(65.1)	(71.0)	(61.1)	(58.2)	(55.0)
Transport and marketing costs	(3.4)	(3.0)	(3.5)	(0.5)	(1.9)	(2.3)	(3.5)	(2.7)
Adjusted operating netback[(1)]	112.7	156.8	132.6	167.1	176.6	152.5	206.2	189.6
General and administrative expenses	(20.2)	(10.6)	(9.0)	(11.3)	(12.3)	(10.7)	(12.2)	(8.4)
Premiums and realised fair value on derivatives	(1.9)	(2.1)	(2.1)	(2.1)	(2.4)	(2.3)	(2.0)	(2.0)
Other[(2)]	(0.9)	(4.6)	(4.3)	(1.9)	4.8	2.8	18.4	3.7
Adjusted EBITDAX[(1)]	89.6	139.5	117.2	151.9	166.7	142.3	210.5	182.8
Adjusted EBITDAX margin (%)[(1)]	47%	61%	58%	65%	67%	66%	79%	74%
Key financial results ($ million)								
Net income	4.0	66.2	57.5	54.9	32.7	58.3	67.0	75.2
Capital and exploration expenditures[(1)]	62.9	47.0	42.3	33.1	54.8	51.5	42.3	36.7
Free Cash Flow[(1)]	94.1	70.8	(50.7)	57.9	123.8	73.4	58.9	129.9
Cash & cash equivalents	160.6	148.6	93.6	135.9	90.8	180.3	120.2	110.8
Net debt[(1)]	934.7	618.3	703.6	636.4	640.1	500.8	511.2	528.7

[(1)] See "Non-IFRS Measures" section. | [(2)] 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. The Company's policy is to hedge between 40% to 60% of its expected net 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 ($/bbl)	Avg. short call strike price ($/bbl)
Put	1Q26	Brent	2,080,200	55.3	–
Put	2Q26	Brent	623,656	55.1	–
Premium collar	2Q26	Brent	1,425,200	55.5	80.0
Put	3Q26	Brent	690,324	58.0	–
Premium collar	3Q26	Brent	340,890	56.5	80.0

Currently, we have hedging positions for 60% of our net production until June 2026, 40% for July and August, and 10% for September volumes.

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 $30 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. Forward rate
Forward	Mar. 2026	USD / COP	$10.0	3,711.2
Forward	Apr. 2026	USD / COP	$10.0	3,736.6
Forward	May. 2025	USD / COP	$10.0	3,765.3

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 total comprehensive income or loss adjusted for financial income and financial expenses, depreciation, depletion and amortisation, income tax expense, exploration expenses, unrealised foreign exchange (gain) / loss, accretion of decommissioning liability, amortisation of debt issuance cost, unrealised fair value (gain) / loss on derivatives, inventory fluctuation, other non-cash items such as impairment of property, plant and equipment and inventory, fair value remeasurements, 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, and non-recurring costs.

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

Adjusted operating breakeven: calculated as the sum of operating expenses per boe of net sales (including lifting, transport, and marketing costs) plus the discount to Brent. The discount to Brent is defined as the difference between the Brent benchmark price and the Company's average realised price.

Adjusted operating netback: calculated as total revenue less lifting, transport and marketing 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 and impairments.

Free Cash Flow ("FCF"): consists of Adjusted EBITDAX further adjusted for exploration drilling expenditures, overhead and seismic expenses and income tax payments, development and maintenance capex, changes in working capital, lease payments, inventory of capitalisable parts/components, decommissioning funding and non-recurring costs.

Net debt: calculated as total indebtedness less cash and cash equivalents.

Net leverage ratio: 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 available amounts of committed credit lines.

Total indebtedness: Total indebtedness includes long term notes, long-term debt and short term debt (which currently consist of the 2028 Notes, the 2030 Notes, drawn amounts of credit from the RCF, Bancolombia loan, Banco de Bogotá loan, Davivienda loan, all gross of unamortised debt issuance costs) and total lease liabilities (current and non-current).

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 consolidated financial statements for the period ended 31 December 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.

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