

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2026

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission file number 001-34018

GRAN TIERRA ENERGY INC.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

98-0479924

(I.R.S. Employer Identification No.)

500 Centre Street S.E.

Calgary, Alberta Canada T2G 1A6

(Address of principal executive offices, including zip code)

(403) 265-3221

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value \$0.001 per share	GTE	NYSE American
		Toronto Stock Exchange
		London Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer
Non-accelerated filer Smaller reporting company
Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

On May 5, 2026, 35,359,890 shares of the registrant's Common Stock, \$0.001 par value, were issued and outstanding.

Quarterly Report on Form 10-Q

Quarterly Period Ended March 31, 2026

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and benefits of the changes in our capital program or expenditures, our liquidity and financial condition and those statements preceded by, followed by or that otherwise include the words "believe", "expect", "anticipate", "intend", "estimate", "project", "target", "goal", "plan", "budget", "objective", "should", "outlook" or similar expressions or variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, our ability to realize the anticipated benefits and operating synergies expected from the acquisition of i3 Energy Plc ("i3Energy"); certain of our operations are located in South America and the Company is pursuing activities in other international jurisdictions, including Azerbaijan, and unexpected problems can arise due to guerilla activity, strikes, local blockades or protests; technical difficulties and operational difficulties may arise which impact the production, transport or sale of our products; other disruptions to local operations; global health events; global and regional changes in the demand, supply, prices, differentials or other market conditions affecting oil and natural gas, including inflation and changes resulting from actual or anticipated tariffs and trade policies, global health crises, geopolitical events, including the ongoing conflicts in Ukraine, the Middle East and Venezuela, or from the imposition or lifting of crude oil production quotas or other actions that might be imposed by OPEC, and other producing countries and the resulting company or third-party actions in response to such changes; changes in commodity prices, including volatility or a prolonged decline in these prices relative to historical or future expected levels; the risk that current global economic and credit conditions may impact oil prices and oil consumption more than we currently predict which could cause further modification of our strategy and capital spending program; prices and markets for oil and natural gas are unpredictable and volatile; the effect of hedges; the accuracy of productive capacity of any particular field; geographic, political and weather conditions can impact the production, transport or sale of our products; our ability to execute our business plan, which may include acquisitions and realize expected benefits from current or future initiatives; such as the expected effectiveness of the exploration and development production sharing agreement ("EDPSA") in Azerbaijan and the timing and execution of the related exploration program; the risk that unexpected delays and difficulties in developing currently owned properties may occur; the ability to replace reserves and production and develop and manage reserves on an economically viable basis; the accuracy of testing and production results and seismic data, pricing and cost estimates (including with respect to commodity pricing and exchange rates); the risk profile of planned exploration activities; the effects of drilling down-dip; the effects of waterflood and multi-stage fracture stimulation operations; the extent and effect of delivery disruptions, equipment performance and costs; actions by third parties; the timely receipt of regulatory or other required approvals for our operating activities; the failure of exploratory drilling to result in commercial wells; unexpected delays due to the limited availability of drilling equipment and personnel; volatility or declines in the trading price of our common stock or bonds; the risk that we do not receive the anticipated benefits of government programs, including government tax refunds; our ability to access debt or equity capital markets from time to time to raise additional capital, increase liquidity, fund acquisitions or refinance debt; our ability to comply with financial covenants in our indentures and make borrowings under our credit agreement; and those factors set out in Part II, Item 1A "Risk Factors" in this Quarterly Report on Form 10-Q and Part I, Item 1A "Risk Factors" in our 2025 Annual Report on Form 10-K (the "2025 Annual Report on Form 10-K"). This information included herein is given as of the filing date of this Quarterly Report on Form 10-Q with the Securities and Exchange Commission ("SEC") and, except as otherwise required by the securities laws, we disclaim any obligation or undertaking to publicly release any updates or revisions to or to withdraw, any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	BOEPD	barrels of oil equivalent per day
BOPD	barrels of oil per day	NGL	natural gas liquids
NAR	net after royalty	boe	barrels of oil equivalent

Sales volumes represent production NAR adjusted for inventory changes. Our oil and gas reserves are reported as NAR. Our production is also reported NAR, except as otherwise specifically noted as "working interest production before royalties".

PART I - Financial Information

Item 1. Financial Statements

Gran Tierra Energy Inc.
Condensed Consolidated Statements of Operations (Unaudited)
(Thousands of U.S. Dollars, Except for Share and Per Share Amounts)

	Three Months Ended March 31,	
	2026	2025
OIL, NATURAL GAS AND NGL SALES (Note 9)	\$ 172,057	\$ 168,173
EXPENSES		
Operating	66,149	67,090
Transportation	5,303	4,551
Other taxes	1,041	481
Depletion, depreciation and accretion (Note 5)	69,874	72,202
General and administrative	34,825	11,409
Severance	2,468	-
Foreign exchange loss	1,425	3,838
Derivative instruments loss (Note 12)	88,410	1,467
Interest expense (Note 6)	49,878	23,235
	<u>319,373</u>	<u>184,273</u>
INTEREST INCOME	401	425
OTHER GAIN (LOSS) (Note 6)	1,148	(52)
LOSS BEFORE INCOME TAXES	<u>(145,767)</u>	<u>(15,727)</u>
INCOME TAX EXPENSE (RECOVERY)		
Current (Note 10)	5,850	8,265
Deferred (Note 10)	(32,445)	(4,712)
	<u>(26,595)</u>	<u>3,553</u>
NET LOSS	<u>\$ (119,172)</u>	<u>\$ (19,280)</u>
OTHER COMPREHENSIVE INCOME		
Foreign currency translation adjustment	(1,085)	191
COMPREHENSIVE LOSS	<u>\$ (120,257)</u>	<u>\$ (19,089)</u>
NET LOSS PER SHARE		
- BASIC and DILUTED	<u>\$ (3.38)</u>	<u>\$ (0.54)</u>
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC and DILUTED (Note 8)	<u>35,299,842</u>	<u>35,777,367</u>

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Condensed Consolidated Balance Sheets (Unaudited)
(Thousands of U.S. Dollars, Except for Share Amounts)

	As at March 31, 2026	As at December 31, 2025
ASSETS		
Current Assets		
Cash and cash equivalents (Note 13)	\$ 124,752	\$ 82,931
Accounts receivable	79,632	32,908
Inventory	46,664	55,384
Taxes receivable (Note 4)	23,181	27,113
Derivatives (Note 12)	444	10,147
Other current assets (Note 13)	14,240	5,044
Total Current Assets	288,913	213,527
Oil and Gas Properties		
Proved	1,102,364	1,154,836
Unproved	101,032	108,339
Total Oil and Gas Properties	1,203,396	1,263,175
Other capital assets	56,675	41,245
Total Property, Plant and Equipment (Note 5)	1,260,071	1,304,420
Other Long-Term Assets		
Deferred tax assets	64,053	56,268
Taxes receivable long-term (Note 4)	11,726	1,912
Other long-term assets (Note 12 and 13)	10,317	9,952
Total Other Long-Term Assets	86,096	68,132
Total Assets	\$ 1,635,080	\$ 1,586,079
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable, accrued liabilities and other (Note 6 and 7)	\$ 402,126	\$ 314,005
Current portion of long-term debt (Note 6 and 12)	21,422	21,212
Taxes payable (Note 4)	12,194	11,906
Derivatives (Note 12)	76,891	-
Equity compensation award liability (Note 8)	31,420	8,569
Total Current Liabilities	544,053	355,692
Long-Term Liabilities		
Long-term debt (Note 6 and 12)	574,354	686,521
Customer advance (Note 7)	230,182	115,909
Deferred tax liabilities	28,161	53,458
Asset retirement obligation	118,170	118,876
Equity compensation award liability (Note 8)	17,264	14,993
Other long-term liabilities (Note 4)	13,976	11,886
Total Long-Term Liabilities	982,107	1,001,643
Contingencies (Note 11)		
Shareholders' Equity		
Common Stock (35,346,466 and 35,298,774 issued and outstanding shares of Common Stock as at March 31, 2026 and December 31, 2025, respectively, par value \$0.001 per share), (Note 8)	9,939	9,939
Additional paid-in capital	1,269,611	1,269,178
Accumulated other comprehensive gain	1,475	2,560
Deficit	(1,172,105)	(1,052,933)
Total Shareholders' Equity	108,920	228,744
Total Liabilities and Shareholders' Equity	\$ 1,635,080	\$ 1,586,079

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Condensed Consolidated Statements of Cash Flows (Unaudited)
(Thousands of U.S. Dollars)

	Three Months Ended March 31,	
	2026	2025
Operating Activities		
Net loss	\$ (119,172)	\$ (19,280)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and accretion (Note 5)	69,874	72,202
Deferred tax recovery (Note 10)	(32,445)	(4,712)
Stock-based compensation expense (recovery) (Note 8)	19,676	(517)
Amortization of debt issuance costs (Note 6)	11,293	3,833
Unrealized foreign exchange (gain) loss	(200)	1,687
(Gain) loss on bond repurchases and exchange (Note 6)	(728)	52
Unrealized derivative instruments loss (Note 12)	77,328	1,910
Cash settlement of asset retirement obligation	(925)	(1,807)
Non-cash lease expenses	1,468	1,736
Non-cash interest expense	4,513	-
Lease payments	(1,687)	(1,567)
Net change in assets and liabilities from operating activities (Note 13)	143,739	19,693
Net cash provided by operating activities	<u>172,734</u>	<u>73,230</u>
Investing Activities		
Additions to property, plant and equipment (Note 5 and 13)	(41,540)	(67,504)
Proceeds on disposition of property, plant and equipment (Note 5)	48,598	-
Net cash provided by (used in) investing activities	<u>7,058</u>	<u>(67,504)</u>
Financing Activities		
Re-purchase of Senior Notes (Note 6)	(8,087)	(1,712)
Repayment of Senior Notes (Note 6)	(125,000)	(24,828)
Re-purchase of shares of Common Stock (Note 8)	-	(2,415)
Proceeds from exercise of stock options	433	-
Lease payments	(4,417)	(2,253)
Net cash used in financing activities	<u>(137,071)</u>	<u>(31,208)</u>
Foreign exchange (loss) gain on cash, cash equivalents and restricted cash and cash equivalents	(535)	38
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	42,186	(25,444)
Cash and cash equivalents and restricted cash and cash equivalents, beginning of period (Note 13)	92,666	111,337
Cash and cash equivalents and restricted cash and cash equivalents, end of period (Note 13)	<u>\$ 134,852</u>	<u>\$ 85,893</u>

Supplemental cash flow disclosures (Note 13)

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Condensed Consolidated Statements of Shareholders' Equity (Unaudited)
(Thousands of U.S. Dollars)

	Three Months Ended March 31,	
	2026	2025
Share Capital		
Balance, beginning of period	\$ 9,939	\$ 9,940
Cancellation of shares of Common Stock (Note 8)	-	(1)
Balance, end of period	\$ 9,939	\$ 9,939
Additional Paid-in Capital		
Balance, beginning of period	\$ 1,269,178	\$ 1,273,343
Exercise of stock options	433	-
Stock-based compensation (Note 8)	-	1,743
Cancellation of shares of Common Stock (Note 8)	-	(5,529)
Balance, end of period	\$ 1,269,611	\$ 1,269,557
Treasury Stock		
Balance, beginning of period	\$ -	\$ (3,165)
Re-purchase of shares of Common Stock (Note 8)	-	(2,414)
Cancellation of shares of Common Stock (Note 8)	-	5,530
Balance, end of period	\$ -	\$ (49)
Accumulated and other comprehensive income (loss)		
Balance, beginning of period	\$ 2,560	\$ (6,736)
Other comprehensive (loss) income	(1,085)	191
Balance, end of period	\$ 1,475	\$ (6,545)
Deficit		
Balance, beginning of period	\$ (1,052,933)	\$ (859,814)
Net loss	(119,172)	(19,280)
Balance, end of period	\$ (1,172,105)	\$ (879,094)
Total Shareholders' Equity	\$ 108,920	\$ 393,808

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Condensed Consolidated Financial Statements (Unaudited)
(Expressed in U.S. Dollars, unless otherwise indicated)

1. Description of Business

Gran Tierra Energy Inc., a Delaware corporation (the “Company” or “Gran Tierra”), is a publicly traded company focused on oil and natural gas exploration and production with assets currently in Colombia, Ecuador and Canada.

2. Significant Accounting Policies

These interim unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (“GAAP”). The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for the fair presentation of results for the interim periods.

The note disclosure requirements of annual audited consolidated financial statements provide additional disclosures required for interim unaudited condensed consolidated financial statements. Accordingly, these interim unaudited condensed consolidated financial statements should be read in conjunction with the Company’s consolidated financial statements as at and for the year ended December 31, 2025, included in the Company’s 2025 Annual Report on Form 10-K.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements, which are included in the Company’s 2025 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements. The Company has evaluated all subsequent events to the date these interim unaudited condensed consolidated financial statements were issued.

Recently Adopted Accounting Pronouncements

In July 2025, FASB issued ASU 2025-05 “Financial Instruments-Credit Losses: Amendments to the Measurement of Credit Losses on Certain Financial Assets”. This ASU provides a practical expedient for estimating expected credit losses on certain short-term receivables and contract assets arising from revenue transactions within the scope of ASC 606. Under the practical expedient, all entities may elect to assume that current conditions as of the balance sheet date would not change for the remaining life of the asset when developing reasonable and supportable forecasts. The ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2025, early adoption is permitted for both interim and annual reporting periods. The Company adopted this ASU effective January 1, 2026. The implementation of this update did not have a material impact on its balance sheet, statement of operations or financial statements disclosures.

3. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company reports segmented information based on internal management reporting used by our Chief Operational Decision Makers (“CODM”), which are the Company’s Chief Executive Officer, Chief Financial Officer, Chief Operating Officer and Vice Presidents across various business functions. CODM allocates resources and assesses performance of each reportable segment based on segmented earnings. The Company determined three reportable segments based on the geographic organization: Colombia, Ecuador and Canada. The “Other” category represents the Company’s corporate activities.

The following tables present information on the Company’s reportable segments and other activities:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2026				
	Colombia	Ecuador	Canada	Other	Total
Oil, natural gas and NGL sales	\$ 102,324	\$ 40,745	\$ 28,988	\$ -	\$ 172,057
Operating expenses	35,042	15,952	15,155	-	66,149
Transportation expenses	2,272	2,554	477	-	5,303
Segmented earnings	\$ 65,010	\$ 22,239	\$ 13,356	\$ -	\$ 100,605
Other taxes					1,041
Depletion, depreciation and accretion (“DD&A”) expenses					69,874

General and administrative expenses	34,825
Severance	2,468
Foreign exchange loss	1,425
Derivative instruments loss	88,410
Interest expense	49,878
Non-segmented expenses	247,921
Other gain	1,148
Interest income	401
Income before income taxes	(145,767)
Income tax recovery	(26,595)
Net loss	\$ (119,172)

Segment capital expenditures	\$ 20,873	\$ 4,737	\$ 15,930	-	\$ 41,540
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Three Months Ended March 31, 2025

(Thousands of U.S. Dollars)	Colombia	Ecuador	Canada	Other	Total
Oil, natural gas and NGL sales	\$ 117,648	\$ 21,023	\$ 29,502	-	\$ 168,173
Operating expenses	42,490	8,073	16,527	-	67,090
Transportation expenses	3,211	1,093	247	-	4,551
Segmented earnings	\$ 71,947	\$ 11,857	\$ 12,728	-	\$ 96,532
Other taxes					481
DD&A expenses					72,202
General and administrative expenses					11,409
Foreign exchange loss					3,838
Derivative instruments loss					1,467
Interest expense					23,235
Non-segmented expenses					112,632
Other loss					(52)
Interest income					425
Income before income taxes					(15,727)
Income tax expense					3,553
Net loss					\$ (19,280)
Segment capital expenditures	\$ 22,669	\$ 20,787	\$ 23,665	383	\$ 67,504

	As at March 31, 2026				
(Thousands of U.S. Dollars)	Colombia	Ecuador	Canada	Other	Total
Property, plant and equipment	\$ 954,686	\$ 168,004	\$ 130,213	\$ 7,168	\$ 1,260,071
All other assets	179,752	65,379	46,652	83,226	375,009
Total Assets	\$ 1,134,438	\$ 233,383	\$ 176,865	\$ 90,394	\$ 1,635,080

	As at December 31, 2025				
(Thousands of U.S. Dollars)	Colombia	Ecuador	Canada	Other	Total
Property, plant and equipment	\$ 935,351	\$ 176,003	\$ 185,226	\$ 7,840	\$ 1,304,420
All other assets	150,524	55,313	39,093	36,729	281,659
Total Assets	\$ 1,085,875	\$ 231,316	\$ 224,319	\$ 44,569	\$ 1,586,079

4. Taxes Receivable and Payable

The table below shows the break-down of taxes receivable, which are comprised of value added tax ("VAT") and income tax receivables and payables:

(Thousands of U.S. Dollars)	As at March 31, 2026		As at December 31, 2025	
Taxes Receivable				
Current				
VAT Receivable	\$	1,975	\$	1,394
Income Tax Receivable		21,206		25,719
	\$	23,181	\$	27,113
Long-Term				
Income Tax Receivable	\$	11,726	\$	1,912
Taxes Payable				
Current				
VAT Payable	\$	(2,767)	\$	(5,189)
Income Tax Payable		(9,427)		(6,717)
	\$	(12,194)	\$	(11,906)
Long-Term				
Income Tax Payable ⁽¹⁾	\$	(2,531)	\$	-
Total Net Taxes Receivable	\$	20,182	\$	17,119

⁽¹⁾Included into other long-term liabilities on the Company's condensed consolidated balance sheet.

The following table shows the movement of VAT and income tax receivables and payables for the period:

(Thousands of U.S. Dollars)	VAT Receivable/(Payable) ⁽¹⁾	Income Tax Receivable	Total Net Taxes Receivable
Balance, as at December 31, 2025	\$ (3,795)	\$ 20,914	\$ 17,119
Collected through direct government refunds	(2,992)	(361)	(3,353)
Collected through sales contracts	(18,209)	-	(18,209)
Taxes paid	23,980	446	24,426
Withholding taxes paid	250	5,221	5,471
Current tax expense	-	(5,850)	(5,850)
Foreign exchange gain	(26)	604	578
Balance, as at March 31, 2026	\$ (792)	\$ 20,974	\$ 20,182

⁽¹⁾ VAT is paid on certain goods and services and collected on sales in Colombia at a rate of 19%.

5. Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at March 31, 2026	As at December 31, 2025
Oil and natural gas properties		
Proved	\$ 5,591,074	\$ 5,587,422
Unproved	101,032	108,339
	5,692,106	5,695,761
Other ⁽¹⁾	101,253	78,780
	5,793,359	5,774,541
Accumulated depletion, depreciation and impairment	(4,533,288)	(4,470,121)
	\$ 1,260,071	\$ 1,304,420

⁽¹⁾ The "other" category includes right-of-use assets for operating and finance leases of \$87.4 million, which had a net book value of \$46.7 million as at March 31, 2026 (December 31, 2025 - \$65.0 million, which had a net book value of \$30.8 million).

During the three months ended March 31, 2026, the Company entered into one new finance lease agreement related to power generation equipment and one new operating office lease agreement in Colombia and recognized right-of-use assets of \$15.6 million and \$4.0 million, respectively, related to these agreements. In addition, modifications to certain existing finance leases for power generation equipment resulted in an increase in right-of use assets of \$2.7 million.

For the three months ended March 31, 2026 and 2025, the Company had no ceiling test impairment losses. The Company used a 12-month unweighted average of the first-day-of-the month prices prior to the ending date of the period ended March 31, 2026 as follows: Brent Crude \$67.58 per boe, Edmonton Light Crude of C\$83.04 per boe, Alberta AECO spot price of C\$1.99 per MMBtu, Edmonton Propane C\$28.38 per boe, Edmonton Butane C\$36.04 per boe and Edmonton Condensate C\$85.94 and for the three months ended March 31, 2025 Brent Crude of \$78.90 per boe, Edmonton Light Crude of C\$98.11 per boe, Alberta AECO spot price of C\$1.51 per MMBtu, Edmonton Propane C\$32.53 per boe, Edmonton Butane C\$48.81 per boe and Edmonton Condensate C\$101.71.

On March 10, 2026, the Company completed the disposition of the entire working interest ("WI") and associated title rights in the Simonette Montney area in Canada effective January 1, 2026, for total cash consideration of C\$66.3 million (US\$48.6 million). The consideration comprised of C\$50.0 million (US\$36.6 million) attributable to the sale of crude oil and natural gas rights, C\$12.5 million (US\$9.2 million) related to the sale of tangible assets and seismic data and economic rights adjustment to effective date of C\$3.8 million (US\$2.8 million). No gain or loss was recognized in the statement of operations because the disposal did not materially change the relationship between capital costs and the proved reserves of oil and natural gas assets.

On March 17, 2026, the Company entered into a strategic partnership with Ecopetrol S.A. to earn, subject to regulatory approvals and conditions precedent, a 49% WI in the Tisquirama Block in Colombia. Under the terms of the agreement, the Company has committed to fund approximately \$47.1 million of a \$92.4 million gross capital program over 40 months, including a minimum Phase 1 investment of \$15.0 million. Upon completion of Phase 1, the Company will be entitled to 49% of production and is expected to assume operatorship. The effective date of the Contract is subject to regulatory approval.

6. Debt and Debt Issuance Costs

The Company's debt as at March 31, 2026, and December 31, 2025, was as follows:

(Thousands of U.S. Dollars)	As at March 31, 2026	As at December 31, 2025
Current		
9.50% Senior Notes	\$ 21,910	\$ 21,910
Unamortized Senior Notes discount	(349)	(496)
Unamortized debt issuance costs	(139)	(202)
	\$ 21,422	\$ 21,212
Long-Term		
7.75% Senior Notes, due May 2027 ("7.75% Senior Notes")	24,201	24,201
9.50% Senior Notes, due October 2029 ("9.50% Senior Notes")	65,729	694,430
9.75% Senior Notes, due April 2031 ("9.75% Senior Notes")	494,353	-
Unamortized Senior Notes discount	(11,106)	(29,365)
Unamortized debt issuance costs ⁽¹⁾	(21,099)	(14,458)
	552,078	674,808
Long-term lease obligation ⁽²⁾	22,276	11,713
	\$ 574,354	\$ 686,521
Total Debt	\$ 595,776	\$ 707,733

⁽¹⁾ Includes \$0.2 million of deferred financing fees related to Canadian revolving credit facility as at March 31, 2026 (December 31, 2025 - \$1.8 million related to Canadian revolving and Colombian credit facilities).

⁽²⁾ The current portion of the lease obligation was included in accounts payable and accrued liabilities on the Company's consolidated balance sheet and totaled \$25.7 million as at March 31, 2026 (December 31, 2025 - \$17.0 million).

Senior Notes

(Thousands of U.S. Dollars)	9.50% Senior Notes	9.75% Senior Notes
Senior Notes, December 31, 2025	\$ 716,340	\$ -
Principal exchanged for 9.75% Senior Notes	(628,701)	628,701
Early participation principal payment	-	(125,000)
Rounding adjustment on exchange	-	(131)
Purchased in the open market	-	(9,217)
Senior Notes principal, March 31, 2026	\$ 87,639	\$ 494,353

During the three months ended March 31, 2026, the Company issued \$503.6 million in aggregate principal amount of its 9.75% Senior Secured Amortizing Notes due 2031 (the "9.75% Senior Notes"), and paid \$125.0 million in cash consideration in exchange for \$628.7 million aggregate principal amount of its 9.50% Senior Notes. The exchange was accounted for as debt modification.

The 9.75% Senior Notes will mature on April 15, 2031, unless earlier redeemed or re-purchased. Subject to adjustment for required minimum denominations, the principal amount of 9.75% Senior Notes will be amortized over three installments as follows: (i) October 15, 2029 - 15% of the principal amount; (ii) October 15, 2030 - 15% of the principal amount; (iii) April 15, 2031 - the remainder of the principal amount. The Company is required to complete mandatory redemption of \$30.0 million aggregate principal amount of 9.75% Senior Notes less any re-purchases in the open market during the year ended December 31, 2026.

At any time, prior to April 15, 2028, the Company may redeem up to 35% of the aggregate principal amount of 9.75% Senior Notes at a redemption price equal to 109.75% of the principal amount. Additionally, the Company may redeem all or a portion

of the 9.75% Senior Notes on or after 2028 at the following redemption prices: 2028 - 104.875%; 2029 - 102.438%; 2030 and thereafter - 100%.

Under the terms of the 9.75% Senior Notes agreement, the Company is required to maintain compliance with the following financial covenants:

- i. consolidated interest coverage ratio of not less than 2.50; and
- ii. consolidated net debt (total debt excluding deferred financing fees debt less cash equivalents) to consolidated adjusted earnings before interest, taxes and DD&A ("EBITDA") of not more than 3.00.

During the three months ended March 31, 2026, the Company re-purchased \$9.2 million of 9.75% Senior Notes for cash consideration of \$8.1 million resulting in a \$0.6 million gain on purchase, which included the write-off of deferred financing fees of \$0.5 million.

As at March 31, 2026, the Company was in compliance with all applicable covenants related to Senior Notes.

Credit facility

As at March 31, 2026, the Company, through its wholly owned subsidiary Gran Tierra Canada Ltd., had a revolving credit facility with National Bank of Canada with a borrowing base of C\$ 100.0 million (US\$71.9 million) and the available commitment of a C\$75.0 million (US\$54.0 million) revolving credit facility comprised of C\$60.0 million (US\$43.2 million) syndicated facility and C\$15.0 million (US\$10.8 million) of operating facility. The drawn down amounts under the revolving credit facility can either be in Canadian or U.S. dollars and bear interest rates equal to either the Canadian prime rate or U.S. Base Rate plus a margin ranging from 2.00% to 4.00% per annum or for CORRA loans and SOFR loans plus a margin ranging from 3.00% to 5.00% per annum. Undrawn amounts under the revolving credit facility bear standby fee ranging from 0.75% to 1.25% per annum. In each case, the margin or standby fee, as applicable is based on Net Debt to EBITDA ratio of Gran Tierra Canada Ltd. The revolving credit facility matures on October 30, 2027. As of March 31, 2026, the revolving credit facility remained undrawn.

Leases

During the three months ended March 31, 2026, the Company entered into one finance lease of \$15.6 million, one operating lease of \$4.0 million, and modified certain existing finance leases, increasing them by \$2.7 million.

The new finance lease has a three-year term and a discount rate of 9.6% and the new operating lease has a five-year term and a discount rate of 9.1%.

Interest Expense

The following table presents the total interest expense recognized in the accompanying interim unaudited condensed consolidated statements of operations:

(Thousands of U.S. Dollars)	Three Months Ended March 31,	
	2026	2025
Contractual interest and other financing expenses	\$ 38,585	\$ 19,402
Amortization of debt issuance costs	11,293	3,833
	\$ 49,878	\$ 23,235

7. Prepayment agreements

During the three months ended March 31, 2026, the Company amended its existing prepayment agreement with Trafigura. The amended agreement provides for total prepayments of up to \$350.0 million, including \$325.0 million available immediately and an additional \$25.0 million available at Trafigura's sole discretion and includes both Ecuadorian and Colombian crude oil production. The term of the amended prepayment agreement is 48 months.

Amounts drawn on this prepayment agreement are to be repaid through future oil deliveries. Shortfalls in crude oil deliveries in any given repayment period can be delivered during the next repayment period within three calendar months or paid in cash thereafter. Amounts under the prepayment facility are subject to interest based on SOFR risk-free rate plus a margin of 4.45% per annum. Under the terms of the prepayment agreement, the Company can repay the outstanding balance of the advance

payment at any time without penalty. The Company was granted a grace period for re-payment of the principal amount drawn under the prepayment agreement with first re-payment starting April 2026.

Pursuant to the amended and restated prepayment agreement, proceeds from the new advance are required to be used exclusively to finance the repurchase or exchange of Senior Notes and to pay fees and expenses associated with the amended agreement.

The Company is required to maintain compliance with the following financial covenants related to amounts drawn under the prepayment agreement semi-annually, calculated on March 31 and September 30 of each year:

- i. Asset Coverage Ratio of at least 150%, calculated using the net present value of the consolidated future cash flows of certain wholly owned subsidiaries of the Company that sell crude oil, projected through the final maturity date and discounted at 10% over the outstanding principal and the interest payable amount on the prepayment agreement at each reporting period. The net present value of the consolidated future cash flows of the Company is required to be based on 90% of the prevailing ICE Brent forward strip.
- ii. Debt Service Coverage Ratio of at least 200%, calculated using the estimated crude oil to be delivered by the Company from any relevant time up to the final maturity date based on 80% of the prevailing ICE Brent forward strip and adjusted for quality differential and transportation discount over the outstanding principal amount under the prepayment agreement.

As at March 31, 2026, there was \$316.5 million outstanding (December 31, 2025 - \$150.0 million) on the oil prepayment agreement. Of this amount, \$86.3 million (December 31, 2025 - \$34.1 million) was classified as a current portion and included in accounts payable and accrued liabilities on the Company's condensed consolidated balance sheet.

8. Share Capital

	Shares of Common Stock
Shares issued and outstanding at December 31, 2025	35,298,774
Shares issued on option exercise	47,692
Shares issued and outstanding at March 31, 2026	<u>35,346,466</u>

As at March 31, 2026, the Company had a share re-purchase program (the "2025 Program") through the facilities of the Toronto Stock Exchange ("TSX"), the NYSE American or alternative programs in Canada or the United States, if eligible. Under the 2025 Program, the Company is able to purchase up to 2,925,720 shares of Common Stock, par value of \$0.001 per share ("Common Stock") representing 10% of the public float as of October 31, 2025, at prevailing market prices at the time of purchase. The 2025 Program will continue for one year and expire on November 5, 2026, or earlier if the 10% maximum is reached.

During the three months ended March 31, 2026, the Company did not re-purchase any shares under the 2025 Program (three months ended March 31, 2025 - 453,050 shares re-purchased under the 2024 program at a weighted average price of \$5.33 per share).

Equity Compensation Awards

The following table provides information about performance stock units ("PSUs"), deferred share units ("DSUs"), restricted share units ("RSUs") and stock option activity for the three months ended March 31, 2026:

	PSUs	DSUs	RSUs	Stock Options	Weighted Average Exercise Price/Stock Option (\$)
	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Stock Options	
Balance, December 31, 2025	7,595,979	876,538	1,064,824	1,043,996	9.61
Granted	4,234,770	230,482	1,048,886	-	-
Exercised	(1,491,419)	-	(326,161)	(48,368)	6.90
Forfeited	(310,528)	-	(35,781)	(2,058)	8.60
Expired	-	-	-	(365,361)	8.23
Balance, March 31, 2026	10,028,802	1,107,020	1,751,768	628,209	10.62

As at March 31, 2026, the equity compensation award liability on the Company's balance sheet included \$2.1 million of current liability related to the Company's outstanding stock options.

For the three months ended March 31, 2026 and 2025, there was \$19.7 million expense and \$0.5 million recovery of stock-based compensation, respectively.

As at March 31, 2026, there was \$70.4 million (December 31, 2025 - \$15.4 million) of unrecognized compensation costs related to unvested PSUs, RSUs and stock options, which are expected to be recognized over a weighted-average period of 2.2 years. During the three months ended March 31, 2026, the Company paid out \$6.0 million for PSUs vested on December 31, 2025 (three months ended March 31, 2025 - \$10.4 million for PSUs vested on December 31, 2024).

During the three months ended March 31, 2026, the Company awarded 1.0 million RSUs to employees pursuant to the existing 2007 Equity Incentive Plan. Under the 2007 Equity Incentive Plan, RSUs will vest one-third each year over a three-year period. Upon vesting, RSUs entitle the holder to receive either the underlying number of shares of the Company's Common Stock or a cash payment equal to the value of the underlying shares of the Company's Common Stock. The Company intends to settle RSUs outstanding as at March 31, 2026, in cash.

Net Income (Loss) per Share

Basic net income or loss per share is calculated by dividing net income or loss attributable to common shareholders by the weighted average number of shares of Common Stock issued and outstanding during each period.

Diluted net income or loss per share is calculated using the treasury stock method for share-based compensation arrangements. The treasury stock method assumes that any proceeds obtained on the exercise of share-based compensation arrangements would be used to purchase shares of Common Stock at the average market price during the period. The weighted average number of shares is then adjusted by the difference between the number of shares issued from the exercise of share-based compensation arrangements and shares re-purchased from the related proceeds. Anti-dilutive shares represent potentially dilutive securities excluded from the computation of diluted income or loss per share as their impact would be anti-dilutive.

Weighted Average Shares Outstanding

For the three months ended March 31, 2026 and 2025, all options were excluded from the diluted loss per share calculation as the options were anti-dilutive.

9. Revenue

	Three Months Ended March 31, 2026			
	Crude Oil	Natural Gas	NGL	Total Revenue
Colombia	102,324	-	-	102,324
Ecuador	40,745	-	-	40,745
Canada	18,738	7,910	2,340	28,988
	\$ 161,807	\$ 7,910	\$ 2,340	\$ 172,057

	Three Months Ended March 31, 2025			
	Crude Oil	Natural Gas	NGL	Total Revenue
Colombia	117,648	-	-	117,648
Ecuador	21,023	-	-	21,023
Canada	18,108	7,878	3,516	29,502
	<u>\$ 156,779</u>	<u>\$ 7,878</u>	<u>\$ 3,516</u>	<u>\$ 168,173</u>

During the three months ended March 31, 2026, the Company's production was sold primarily to one major customer, representing 74% of the total Company's sales volumes (three months ended March 31, 2025 - one major customer, representing 65% of total Company's sales volumes), reported in each of the reportable segments.

As at March 31, 2026, accounts receivable included \$ 27.6 million of accrued sales revenue related to March 2026 production (December 31, 2025 - \$14.8 million related to December 2025 production).

10. Taxes

The Company's effective tax rate was 18% for the three months ended March 31, 2026, compared to a negative 23% in the corresponding period of 2025.

Current income tax expense was \$5.9 million for the three months ended March 31, 2026, compared to \$8.3 million in the corresponding period of 2025, primarily due to lower taxable income.

For the three months ended March 31, 2026, the Company recognized a deferred tax recovery of \$32.4 million, primarily attributable to an increase in deductible temporary differences arising from tax losses generated during the period and accruals. This recovery was partially offset by temporary differences related to accelerated tax depreciation in excess of accounting depreciation.

For the three months ended March 31, 2025, the deferred income tax recovery of \$4.7 million was mainly due to the use of a higher enacted tax rate on Colombian tax losses. These were partially offset by higher tax depreciation relative to accounting depreciation.

For the three months ended March 31, 2026, the difference between the effective tax rate of 18% and the 21% statutory tax rate was primarily due to an increase in the non-deductible foreign translation adjustments and other permanent differences. This was partially offset by an increase in the impact of foreign taxes.

For the three months ended March 31, 2025, the difference between the effective tax rate of negative 23% and the 21% statutory tax rate was primarily due to an increase in the non-deductible foreign translation adjustments, other permanent differences and valuation allowance. This was partially offset by an increase in the impact of foreign taxes.

11. Contingencies

Legal Proceedings

The Company has several lawsuits and claims pending. The outcome of the lawsuits and disputes cannot be predicted with certainty; the Company believes the resolution of these matters would not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows. The Company records costs as they are incurred or become probable and determinable.

Letters of Credit and Other Credit Support

At March 31, 2026, the Company had provided letters of credit and other credit support totaling \$ 222.5 million, of which \$61.3 million was related to capital commitments in the Suroriente Block and \$0.5 million related to transportation capacity in Canada with the remaining as security relating to work commitment guarantees in Colombia and Ecuador contained in exploration contracts, other capital or operating requirements (December 31, 2025 - \$209.0 million).

12. Financial Instruments and Fair Value Measurement

Financial Instruments

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to market participants to settle liability at the measurement date. For financial instruments carried at fair value, GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels:

- Level 1 - Inputs representing quoted market prices in active markets for identical assets and liabilities
- Level 2 - Inputs other than quoted prices included within Level 1 that are observable for the assets and liabilities, either directly or indirectly
- Level 3 - Unobservable inputs for assets and liabilities

At March 31, 2026, the Company's financial instruments recognized on the balance sheet consist of cash and cash equivalents, restricted cash and cash equivalents, accounts receivable, derivatives, accounts payable and accrued liabilities, current portion of long-term debt, long-term debt and other long-term liabilities. The Company uses appropriate valuation techniques based on the available information to measure the fair values of assets and liabilities.

Fair Value Measurement

The following table presents the Company's fair value measurements of its financial instruments as of March 31, 2026, and December 31, 2025:

(Thousands of U.S. Dollars)	As at March 31, 2026	As at December 31, 2025
Level 1		
Liabilities		
7.75% Senior Notes	\$ 20,329	\$ 19,784
9.50% Senior Notes	80,253	505,020
9.75% Senior Notes	435,958	-
	<u>\$ 536,540</u>	<u>\$ 524,804</u>
Level 2		
Assets		
Restricted cash and cash equivalents - long-term ⁽¹⁾	\$ 10,100	\$ 9,735
Foreign currency derivatives - current	444	10,147
	<u>\$ 10,544</u>	<u>\$ 19,882</u>
Liabilities		
Commodity derivatives - current	\$ 76,891	-
	<u>\$ 76,891</u>	<u>\$ -</u>

⁽¹⁾ The long-term portion of restricted cash and cash equivalents is included in the other long-term assets on the Company's condensed consolidated balance sheet.

The fair values of cash and cash equivalents, current restricted cash and cash equivalents, accounts receivable and accounts payable, and accrued liabilities approximate their carrying amounts due to the short-term maturity of these instruments.

Restricted Cash and Cash Equivalents - Long-Term

The fair value of long-term restricted cash and cash equivalents approximate its carrying value because interest rates are variable and reflective of market rates.

Senior Notes

Financial instruments recorded at amortized cost at March 31, 2026, were the Senior Notes (Note 6).

At March 31, 2026, the carrying amounts of the 7.75% Senior Notes, 9.50% Senior Notes and 9.75% Senior Notes were \$24.0 million, \$83.5 million and \$466.2 million, respectively, which represented the aggregate principal amounts less unamortized debt issuance costs and discounts, and the fair values were \$20.3 million, \$80.3 million and \$436.0 million, respectively.

Derivative asset and derivative liability

The fair value of derivatives is estimated based on various factors, including quoted market prices in active markets and quotes from third parties. The Company also performs an internal valuation to ensure the reasonableness of third party quotes. In consideration of counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers whether such counterparty has the ability to meet its potential repayment obligations associated with the derivative transactions.

(Thousands of U.S. Dollars)	Three Months Ended March 31,	
	2026	2025
Commodity price derivative loss	\$ 88,618	\$ 1,467
Foreign currency derivative gain	(208)	-
Derivative instruments loss	\$ 88,410	\$ 1,467

Commodity Price Risk

The Company may at times utilize commodity price derivatives to manage the variability in cash flows associated with the forecasted sale of its oil production, reduce commodity price risk and provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending. As at March 31, 2026, the Company had outstanding commodity price derivative positions in Canada and Colombia as follows:

Oil

Type of Instrument	Start Period	End Period	Volume bbl/d	Reference	Sold Put (C\$/bbl or \$/bbl Weighted Average)	Purchased Put (C\$/bbl or \$/bbl Weighted Average)	Sold Call (C\$/bbl or \$/bbl Weighted Average)	Premium (C\$/bbl or \$/bbl Weighted Average)
3 Way	April 01, 2026	June 30, 2026	11,500	Brent	48.26	58.48	72.03	-
Collar	April 01, 2026	June 30, 2026	1,000	Brent	-	60.00	76.75	-
3 Way	April 01, 2026	June 30, 2026	1,000	WTI CMA	C\$ 62.50	C\$ 72.50	C\$ 103.70	C\$ 0.95
Collar	April 01, 2026	June 30, 2026	500	WTI CMA	- C\$	C\$ 75.00	C\$ 91.95	-
Call Option	April 01, 2026	June 30, 2026	4,500	Brent	-	-	102.22	9.96
Call Option	April 01, 2026	June 30, 2026	500	WTI CMA	-	- C\$	130.00	C\$ 13.45
Put Option	April 01, 2026	June 30, 2026	2,500	Brent	-	64.00	-	4.06
3 Way	July 01, 2026	September 30, 2026	14,000	Brent	48.79	58.79	71.35	-
Put Option	July 01, 2026	September 30, 2026	500	Brent	-	60.00	-	4.30
3 Way	July 01, 2026	September 30, 2026	1,000	WTI CMA	C\$ 62.50	C\$ 72.50	C\$ 103.70	C\$ 0.95
Collar	July 01, 2026	September 30, 2026	500	WTI CMA	- C\$	C\$ 75.00	C\$ 91.95	-
3 Way	October 01, 2026	December 31, 2026	14,000	Brent	48.43	58.43	70.87	-
Put Option	October 01, 2026	December 31, 2026	500	Brent	-	60.00	-	4.30
3 Way	October 01, 2026	December 31, 2026	500	WTI CMA	C\$ 60.00	C\$ 70.00	C\$ 107.00	C\$ 1.90
Collar	October 01, 2026	December 31, 2026	500	WTI CMA	- C\$	C\$ 70.00	C\$ 92.47	C\$ -
3 Way	January 01, 2027	March 31, 2027	3,000	Brent	58.33	71.67	89.55	-

Natural Gas

Type of Instrument	Start Period	End Period	Volume, GJ/day	Reference	Sold Swap (C\$/GJ, Weighted Average)	Purchased Put (C\$/GJ, Weighted Average)	Sold Call (C\$/GJ, Weighted Average)
Swap	April 01, 2026	June 30, 2026	20,000	Aeco 5A	2.71	-	-
Swap	July 01, 2026	September 30, 2026	20,000	Aeco 5A	2.71	-	-
Swap	October 01, 2026	December 31, 2026	6,739	Aeco 5A	2.71	-	-

Foreign Exchange Risk

The Company is exposed to foreign exchange risk arising from Colombian and Canadian operations predominantly related to operating and transportation costs. Revenue and general and administrative expenses associated with the Company's Canadian operations are also subject to foreign currency fluctuations. To mitigate exposure to fluctuations in foreign exchange, the Company may enter into foreign currency exchange derivatives.

As at March 31, 2026, the Company had the following outstanding foreign currency exchange derivative positions:

Period and Type of Instrument	U.S. Dollars Amount Hedged (Thousands of U.S. Dollars)	COP Equivalent of Amount Hedged (Millions of COP) ⁽¹⁾	Reference	Floor Price (COP, Weighted Average)	Cap Price (COP, Weighted Average)
Collars: April 2026, to March 2027	12,000	44,040	COP	3,790	4,080

⁽¹⁾ At March 31, 2026 foreign exchange rate.

Subsequent to March 31, 2026, the Company entered into the following foreign currency exchange derivative positions:

Period and Type of Instrument	U.S. Dollars Amount Hedged (Thousands of U.S. Dollars)	COP Equivalent of Amount Hedged (Millions of COP) ⁽¹⁾	Reference	Floor Price (COP, Weighted Average)	Cap Price (COP, Weighted Average)
Collars: May 2026, to April 2027	24,000	88,080	COP	3,725	4,004

⁽¹⁾ At March 31, 2026 foreign exchange rate.

13. Supplemental Cash Flow Information

The following table provides a reconciliation of cash and cash equivalents and restricted cash and cash equivalents shown as a sum of these amounts in the interim unaudited condensed consolidated statements of cash flows:

(Thousands of U.S. Dollars)	As at March 31,		As at December 31,	
	2026	2025	2025	2024
Cash and cash equivalents	\$ 124,752	\$ 76,566	\$ 82,931	\$ 103,379
Restricted cash and cash equivalents - current ⁽¹⁾	-	1,142	-	1,142
Restricted cash and cash equivalents - long-term ⁽²⁾	10,100	8,185	9,735	6,816
	<u>\$ 134,852</u>	<u>\$ 85,893</u>	<u>\$ 92,666</u>	<u>\$ 111,337</u>

⁽¹⁾ Included in other current assets on the Company's condensed consolidated balance sheet.

⁽²⁾ Included in other long-term assets on the Company's condensed consolidated balance sheet.

Net changes in assets and liabilities from operating activities were as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31,	
	2026	2025
Accounts receivable and other long-term assets	\$ (46,805)	\$ 5,703
Derivatives	9,587	-
Prepays and inventory	(3,405)	3,239
Oil prepayment proceeds	166,500	-
Accounts payable and accrued liabilities, and other long-term liabilities	20,631	19,204
Taxes receivable and payable	(2,769)	(8,453)
Net changes in assets and liabilities from operating activities	\$ 143,739	\$ 19,693

Net changes in working capital from investing activities were as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31,	
	2026	2025
Additions to property, plant and equipment	\$ (45,359)	\$ (94,727)
Increase in accounts payable and accrued liabilities	4,281	26,567
(Increase) decrease in accounts receivable	(462)	656
Net cash additions to property, plant and equipment	\$ (41,540)	\$ (67,504)

The following table provides additional supplemental cash flow disclosures:

(Thousands of U.S. Dollars)	Three Months Ended March 31,	
	2026	2025
Cash paid for income taxes	\$ 24,426	\$ -
Cash paid for withholding taxes	\$ 5,471	\$ 6,784
Cash paid for interest	\$ 20,580	\$ 828
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	\$ 45,510	\$ 88,338

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q, as well as "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the "Financial Statements and Supplementary Data" included in Part II, Items 7 and 8, respectively, of our 2025 Annual Report on Form 10-K. Please see the cautionary language at the beginning of this Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements and the risk factors described in Part II, Item 1A "Risk Factors" of this Quarterly Report on Form 10-Q, as well as Part I, Item 1A "Risk Factors" in our 2025 Annual Report on Form 10-K.

Financial and Operational Highlights

Key Highlights for the first quarter of 2026

- Net loss for the first quarter of 2026 was \$119.2 million or \$3.38 per share basic and diluted, compared to a net loss of \$19.3 million or \$0.54 per share basic and diluted for the first quarter of 2025 and a net loss of \$141.1 million for the prior quarter. The following non-cash items were the main contributors to net loss for the first quarter of 2026: \$77.3 million unrealized mark-to-market hedging loss, \$19.7 million stock-based compensation remeasurement, \$11.3 million amortization of deferred financing fees and \$4.5 million oil prepayment interest
- Loss before income taxes for the first quarter of 2026 was \$145.8 million, compared to loss before income taxes of \$15.7 million for the first quarter of 2025 and loss before income taxes of \$177.8 million for the prior quarter
- Brent oil price averaged \$78.38 per bbl during the quarter, an increase of 5% from the comparative period of 2025, and a 24% increase from the prior quarter. Castilla, Vasconia and Oriente differentials averaged \$9.67, \$5.91 and \$8.17 per bbl during the quarter, an increase of 81%, 160% and 7% from the comparable period of 2025, and an increase of 49%, 73% for Castilla and Vasconia differentials and 3% decrease for Oriente differential from the prior quarter, respectively
- Adjusted EBITDA⁽²⁾ was \$73.9 million for the first quarter of 2026, a decrease from \$85.2 million in the first quarter of 2025, and an increase from \$52.5 million in the prior quarter
- Funds flow from operations⁽²⁾ decreased to \$42.8 million compared to \$55.3 million in the first quarter of 2025, and increased from \$26.8 million in the prior quarter
- NAR production for the first quarter of 2026 decreased by 2% to 37,741 BOEPD, compared to 38,563 BOEPD in the first quarter of 2025, and decreased by 4% from 39,464 BOEPD in the prior quarter
- NAR Sales volumes for the first quarter of 2026 increased by 3% to 40,267 BOEPD, compared to 39,024 BOEPD in the first quarter of 2025 and increased by 12% from 35,984 BOEPD in the prior quarter
- Oil, natural gas and NGL sales for the first quarter of 2026 increased by 2% to \$172.1 million, compared to the first quarter of 2025, due to higher sales volumes driven by selling production from the newly acquired Perico Block in Ecuador and increase in Brent price, offset by higher quality and transportation discounts in Colombia. Higher quality and transportation discounts incurred due to using alternative transportation route associated with Putumayo production which was significantly more expensive and resulted in approximately \$4.1 million for the current quarter. Oil, natural gas and NGL sales increased by 32% from \$129.9 million in the prior quarter due to higher oil prices, and increase in sales volumes, partially offset by higher differentials. During the first quarter, we had two liftings in Ecuador compared to one in the prior quarter. The sales price in Ecuador is the average Brent price less discounts for the month prior to lifting (M-1). During the current quarter, we sold our January 2026 production in Ecuador at the average Brent price of December 2025 and March production at the average Brent price of February 2026
- Operating expenses decreased by 1% or \$0.85 per boe to \$66.1 million or \$18.25 per boe when compared to the first quarter of 2025, due to lower workover activities, lower power generation and field personnel costs associated with head-count optimization partially offset by inventory fluctuations due to the sale of oil inventory accumulated at the end of the previous quarter. Operating expenses increased by 16% or by \$0.98 per boe from \$57.2 million or \$17.27 per boe in the prior quarter primarily a result of inventory fluctuations due to the sale of oil inventory accumulated at the end of the previous quarter partially offset by lower workover activities and lower operating costs across various categories
- Transportation expenses increased by 17% when compared to the first quarter of 2025 and increased by 44% compared to the prior quarter primarily due to higher sales volumes transported in Ecuador during the current quarter
- Gross profit increased to \$36.7 million compared to \$28.1 million in first quarter of 2025 and \$0.9 million in the prior quarter
- Operating netback⁽²⁾ was \$100.6 million compared to \$96.5 million in the first quarter of 2025 and \$69.1 million in the prior quarter

- Quality and transportation discounts per boe in South America increased for the first quarter of 2026 to \$19.04 compared to \$11.58 in the first quarter of 2025 and \$12.30 in the prior quarter, due to higher differentials and transportation discounts. Higher transportation discounts were incurred due to utilizing alternative transportation route associated with Putumayo production in Colombia which was significantly more expensive and resulted in approximately \$4.1 million for the current quarter
- Quality and transportation discounts for oil per boe in Canada increased for the first quarter of 2026 to \$9.64 compared to \$7.48 in the first quarter of 2025 due to higher pipeline tariffs related to new wells drilled and decreased from \$10.35 in the prior quarter
- General and administrative (“G&A”) expenses before stock-based compensation for the first quarter of 2026 increased to \$15.1 million compared to \$11.9 million in the first quarter of 2025 due to higher consulting costs attributable to optimization projects and decreased from \$16.8 million in the prior quarter due to headcount optimization measures implemented during the current quarter
- Capital expenditures for the first quarter of 2026 were \$45.4 million compared to \$94.7 million in the first quarter of 2025 and \$53.0 million in the prior quarter
- During the first quarter, we entered into a strategic partnership with Ecopetrol S.A. to earn, subject to regulatory approvals and conditions precedent, a 49% WI in the Tisquirama Block in Colombia
- During the first quarter of 2026, we completed the disposition of our entire working interest and associated title rights in the Simonette Montney area in Canada
- During the first quarter of 2026 we entered into an exploration, development and production sharing agreement with the State Oil Company of the Republic of Azerbaijan, for the onshore Guba-Khazaryani region in Azerbaijan, expanding our international exploration portfolio

(Thousands of U.S. Dollars, unless otherwise indicated)	Three Months Ended March 31,			Three Months Ended December 31,
	2026	2025	% Change	2025
Average Daily Volumes (BOEPD)				
Consolidated				
Working Interest ("WI") Production Before Royalties	45,497	46,647	(2)	46,344
Royalties	(7,756)	(8,084)	(4)	(6,880)
Production NAR	37,741	38,563	(2)	39,464
Decrease (increase) in Inventory	2,526	461	448	(3,480)
Sales ⁽¹⁾	40,267	39,024	3	35,984
Net Loss	\$ (119,172)	\$ (19,280)	518	\$ (141,148)
Operating Netback				
Gross Profit	\$ 36,697	\$ 28,101	31	\$ 851
Depletion and Accretion	\$ 63,908	\$ 68,431	(7)	\$ 68,236
Operating Netback ⁽²⁾	\$ 100,605	\$ 96,532	4	\$ 69,087
G&A Expenses before Stock-Based Compensation	\$ 15,149	\$ 11,926	27	\$ 16,817
G&A Stock-Based Compensation Expense (Recovery)	19,676	(517)	3,906	3,042
G&A Expenses, including Stock-Based Compensation	\$ 34,825	\$ 11,409	205	\$ 19,859
Adjusted EBITDA ⁽²⁾	\$ 73,935	\$ 85,162	(13)	\$ 52,473
Funds Flow from Operations ⁽²⁾	\$ 42,823	\$ 55,344	(23)	\$ 26,827
Capital Expenditures (before changes in working capital)	\$ 45,359	\$ 94,727	(52)	\$ 53,040

⁽¹⁾ Sales volumes represent production NAR adjusted for inventory changes.

⁽²⁾ Non-GAAP measures.

Gross profit is derived from oil, gas and NGL sales, less operating and transportation expenses, and depletion and accretion related to producing assets. Gross profit does not include depreciation of administrative assets, asset impairment, general and administrative expenses, interest, taxes or other non-operating items.

Operating netback, EBITDA, adjusted EBITDA, and funds flow from operations are non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Management views these measures as financial performance measures. Investors are cautioned that these measures should not be construed as alternatives to oil sales, net income (loss) or other measures of financial performance as determined in accordance with GAAP. Our method of calculating these measures may differ from other companies and, accordingly, may not be comparable to similar measures used by other companies. Disclosure of each non-GAAP financial measure is preceded by the corresponding GAAP measure so as not to imply that more emphasis should be placed on the non-GAAP measure.

Operating netback, as presented, is defined as gross profit adjusted for depletion and accretion related to producing assets. Management believes that operating netback is a useful supplemental measure for management and investors to analyze financial performance and provides an indication of the results generated by our principal business activities prior to the consideration of other income and expenses. A reconciliation from gross profit to operating netback is provided in the table below.

Colombia (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Gross Profit (Loss)	\$ 24,377	\$ 26,948	\$ (2,865)
Adjustments to reconcile gross profit to operating netback			
Depletion and accretion (*)	40,633	44,999	49,383
Operating netback (non-GAAP)	\$ 65,010	\$ 71,947	\$ 46,518

(*) Calculated as DD&A expenses for the three months ended March 31, 2026 and 2025 of \$46.4 million and \$48.7 million less depreciation of administrative assets of \$5.7 million and \$3.7 million, respectively. For the prior quarter, calculated as DD&A expenses of \$53.3 million, less depreciation of administrative assets of \$3.9 million.

Ecuador (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Gross Profit	\$ 6,378	\$ 1,361	\$ 3,678
Adjustments to reconcile gross profit to operating netback			
Depletion and accretion (*)	15,861	10,496	5,258
Operating netback (non-GAAP)	\$ 22,239	\$ 11,857	\$ 8,936

(*) Calculated as DD&A expenses for the three months ended March 31, 2026 and 2025 of \$16.0 million and \$10.5 million less depreciation of administrative assets of \$0.1 million and nil, respectively. For the prior quarter, calculated as DD&A expenses of \$5.5 million, less depreciation of administrative assets of \$0.3 million.

Canada (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Gross Profit (Loss)	\$ 5,942	\$ (208)	\$ 38
Adjustments to reconcile gross profit to operating netback			
Depletion and accretion (*)	7,414	12,936	13,595
Operating netback (non-GAAP)	\$ 13,356	\$ 12,728	\$ 13,633

(*) Same as DD&A expenses for the three months ended March 31, 2026 and 2025 and the prior quarter.

Total Consolidated (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Gross Profit	\$ 36,697	\$ 28,101	\$ 851
Adjustments to reconcile gross profit to operating netback			
Depletion and accretion (*)	63,908	68,431	68,236
Operating netback (non-GAAP)	\$ 100,605	\$ 96,532	\$ 69,087

(*) Calculated as DD&A expenses for the three months ended March 31, 2026 and 2025 of \$69.9 million and \$72.2 million less depreciation of administrative assets of \$6.0 million and \$3.8 million, respectively. For the prior quarter, calculated as DD&A expenses of \$72.5 million, less depreciation of administrative assets of \$4.3 million.

EBITDA, as presented, is defined as net income (loss) adjusted for depletion, depreciation and accretion ("DD&A") expenses, interest expense, and income tax expense or recovery. Adjusted EBITDA, as presented, is defined as EBITDA adjusted for asset impairment, severance expense, non-cash lease expense, lease payments, foreign exchange gains or losses, stock-based compensation expense or recovery, other non-cash gains or losses and unrealized derivative instruments gains or losses. Management uses this supplemental measure to analyze performance and income generated by our principal business activities prior to the consideration of how non-cash items affect that income and believes that this financial measure is a useful supplemental information for investors to analyze our performance and financial results. A reconciliation from net income (loss) to EBITDA and adjusted EBITDA is as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
Net loss	\$ (119,172)	\$ (19,280)	\$ (141,148)
Adjustments to reconcile net loss to EBITDA and Adjusted EBITDA			
DD&A expenses	69,874	72,202	72,535
Interest expense	49,878	23,235	28,261
Income tax (recovery) expense	(26,595)	3,553	(36,678)
EBITDA (non-GAAP)	\$ (26,015)	\$ 79,710	\$ (77,030)
Asset impairment	-	-	136,261
Severance	2,468	-	-
Non-cash lease expense	1,468	1,736	1,173
Lease payments	(1,687)	(1,567)	(1,287)
Foreign exchange loss	1,425	3,838	896
Stock-based compensation expense (recovery)	19,676	(517)	3,042
Other non-cash (gain) loss	(728)	52	(2,913)
Unrealized derivative instruments loss (gain)	77,328	1,910	(7,669)
Adjusted EBITDA (non-GAAP)	\$ 73,935	\$ 85,162	\$ 52,473

Funds flow from operations, as presented, is defined as net loss adjusted for DD&A expenses, asset impairment, deferred income tax expense or recovery, stock-based compensation expense or recovery, amortization of debt issuance costs, Senior Notes exchange fees, non-cash interest, non-cash lease expense, lease payments, unrealized foreign exchange gain or loss, unrealized derivative instruments gains or loss and other non-cash gains or losses. Management uses this financial measure to analyze performance and income generated by our principal business activities prior to the consideration of how non-cash items affect that income and believes that this financial measure is also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net loss to funds flow from operations is as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
Net loss	\$ (119,172)	\$ (19,280)	\$ (141,148)
Adjustments to reconcile net loss to funds flow from operations			
DD&A expenses	69,874	72,202	72,535
Asset impairment	-	-	136,261
Deferred income tax recovery	(32,445)	(4,712)	(38,055)
Stock-based compensation expense (recovery)	19,676	(517)	3,042
Amortization of debt issuance costs	11,293	3,833	4,759
Senior Notes exchange fees	12,903	-	-
Non-cash interest	4,513	-	2,025
Non-cash lease expense	1,468	1,736	1,173
Lease payments	(1,687)	(1,567)	(1,287)
Unrealized foreign exchange (gain) loss	(200)	1,687	(1,896)
Unrealized derivative instruments loss (gain)	77,328	1,910	(7,669)
Other non-cash (gain) loss	(728)	52	(2,913)
Funds flow from operations (non-GAAP)	\$ 42,823	\$ 55,344	\$ 26,827

Additional Operational Results

(Thousands of U.S. Dollars)	Three Months Ended March 31,			Three Months Ended December 31,
	2026	2025	% Change	2025
Oil, natural gas and NGL sales	\$ 172,057	\$ 168,173	2	\$ 129,929
Operating expenses	66,149	67,090	(1)	57,160
Transportation expenses	5,303	4,551	17	3,682
Operating netback ⁽¹⁾	100,605	96,532	4	69,087
Other taxes	1,041	481	116	657
DD&A expenses	69,874	72,202	(3)	72,535
Asset impairment	-	-	-	136,261
Derivative instruments loss (gain)	88,410	1,467	5,927	(8,426)
G&A expenses before stock-based compensation	15,149	11,926	27	16,817
G&A stock-based compensation expense (recovery)	19,676	(517)	3,906	3,042
Severance	2,468	-	100	-
Foreign exchange loss	1,425	3,838	(63)	896
Interest expense	49,878	23,235	115	28,261
	247,921	112,632	120	250,043
Other gain (loss)	1,148	(52)	(2,308)	2,913
Interest income	401	425	(6)	217
Loss before income taxes	(145,767)	(15,727)	827	(177,826)
Current income tax expense	5,850	8,265	(29)	1,377
Deferred income tax recovery	(32,445)	(4,712)	589	(38,055)
Total income tax (recovery) expense	(26,595)	3,553	(849)	(36,678)
Net loss	\$ (119,172)	\$ (19,280)	518	\$ (141,148)
Sales Volumes (NAR)				
Total sales volumes, BOEPD	40,267	39,024	3	35,984
Brent Price per bbl	\$ 78.38	\$ 74.98	5	\$ 63.08
WTI Price per bbl	\$ 72.73	\$ 71.47	2	\$ 59.24
AECO Price C\$ per GJ	1.91	2.05	(7)	2.11
Consolidated Results of Operations per boe Sales Volumes NAR				
Oil, natural gas and NGL sales	\$ 47.48	\$ 47.88	(1)	\$ 39.25
Operating expenses	18.25	19.10	(4)	17.27
Transportation expenses	1.46	1.30	12	1.11
Operating netback ⁽¹⁾	27.77	27.48	1	20.87
Other taxes	0.29	0.14	110	0.20
DD&A expenses	19.28	20.56	(6)	21.91

Asset impairment	-	-	-	41.16
Derivative instruments loss (gain)	24.40	0.42	5,741	(2.55)
G&A expenses before stock-based compensation	4.18	3.40	23	5.08
G&A stock-based compensation expense (recovery)	5.43	(0.15)	3,789	0.92
Severance	0.68	-	100	-
Foreign exchange loss	0.39	1.09	(64)	0.27
Interest expense	13.76	6.62	108	8.54
	68.41	32.07	113	75.53
Other gain (loss)	0.32	(0.01)	(2,240)	0.88
Interest income	0.11	0.12	(9)	0.07
Loss before income taxes	(40.21)	(4.48)	798	(53.71)
Current income tax expense	1.61	2.35	(31)	0.42
Deferred income tax recovery	(8.95)	(1.34)	567	(11.50)
Total income tax (recovery) expense	(7.34)	1.01	(827)	(11.08)
Net loss	\$ (32.87)	\$ (5.49)	499	\$ (42.63)

(1) Operating netback is a non-GAAP measure that does not have any standardized meaning prescribed under GAAP. Refer to note 2 "Non-GAAP measures" in "Financial and Operational Highlights" for a definition of this measure.

Oil, Natural Gas and NGL Production and Sales Volumes, BOEPD

Average Daily Volumes (BOEPD) - Colombia	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
WI production before royalties	21,319	25,652	23,259
Royalties	(3,230)	(4,420)	(3,013)
Production NAR	18,089	21,232	20,246
Decrease (increase) in inventory	799	(379)	(908)
Sales	18,888	20,853	19,338
Royalties, % of working interest production before royalties	15 %	17%	13%

Average Daily Volumes (BOEPD) - Ecuador	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
WI production before royalties	8,759	4,034	6,898
Royalties	(2,584)	(1,424)	(1,925)
Production NAR	6,175	2,610	4,973
Decrease (increase) in inventory	1,727	840	(2,572)
Sales	7,902	3,450	2,401
Royalties, % of working interest production before royalties	30 %	35%	28%

Average Daily Volumes (BOEPD) - Canada	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
			2025

WI production before royalties	15,419	16,961	16,187
Royalties	(1,942)	(2,240)	(1,942)
Production NAR	13,477	14,721	14,245
Sales	13,477	14,721	14,245

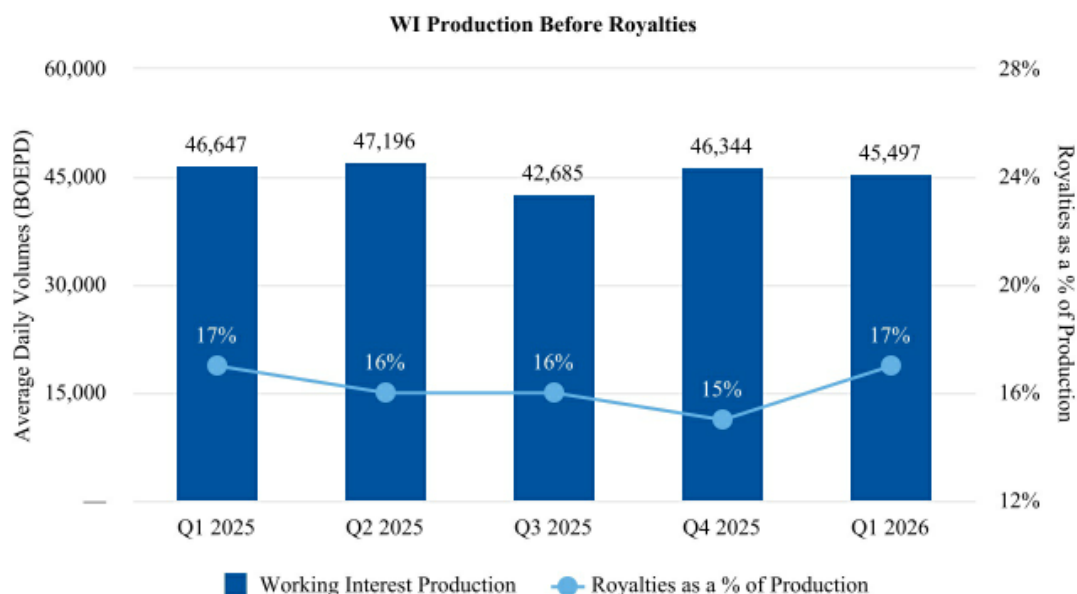
Royalties, % of working interest production before royalties 13 % 13% 12%

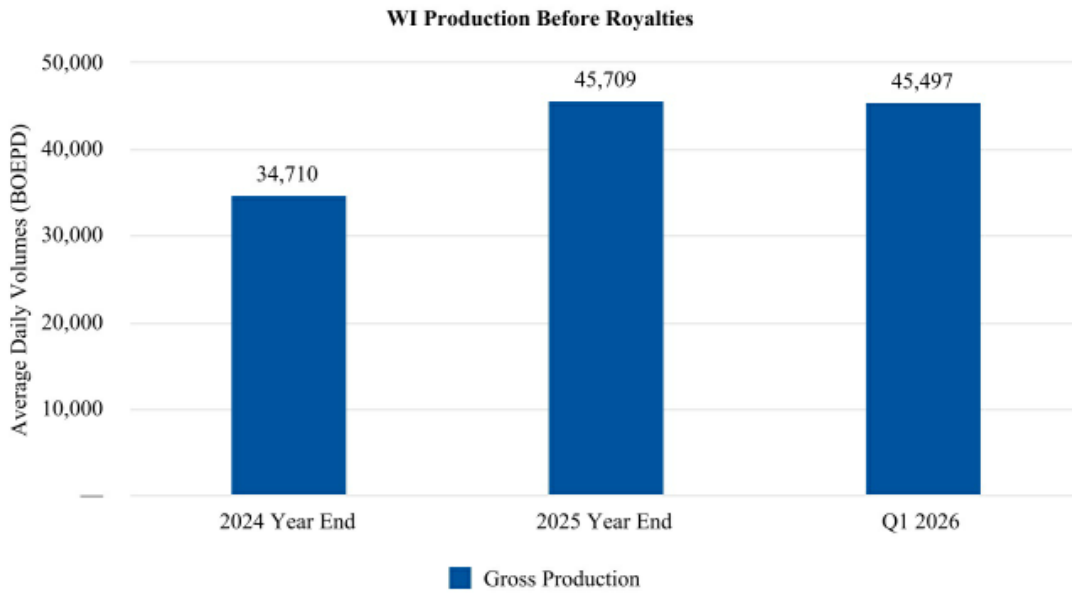
Average Daily Volumes (BOEPD) - Total Company	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
WI production before royalties	45,497	46,647	46,344
Royalties	(7,756)	(8,084)	(6,880)
Production NAR	37,741	38,563	39,464
Decrease (increase) in inventory	2,526	461	(3,480)
Sales	40,267	39,024	35,984

Royalties, % of working interest production before royalties 17 % 17% 15%

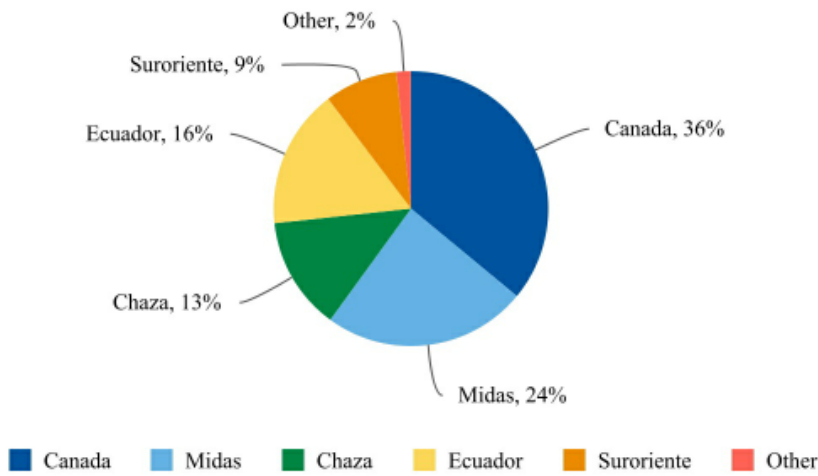
Oil, natural gas and NGL production NAR for the three months ended March 31, 2026, decreased by 2% to 37,741 BOEPD compared to the corresponding period of 2025 due to lower production in Acordionero field in Colombia and the sale of Simonette area in Canada, partially offset by higher than anticipated production results from Conejo-1 well in Charapa Block and additional production from Perico Block in Ecuador acquired in December 2025. Oil, natural gas and NGL production NAR decreased by 4% compared to the prior quarter for the same reason mentioned above.

Royalties as a percentage of production for the three months ended March 31, 2026 were comparable to the corresponding period of 2025. Royalties as a percentage of production increased 2% compared to the prior quarter commensurate with the increase in benchmark oil prices and the price sensitive royalty regime in Colombia, Ecuador, and Canada.





NAR Production by Block for the Three Months Ended March 31, 2026



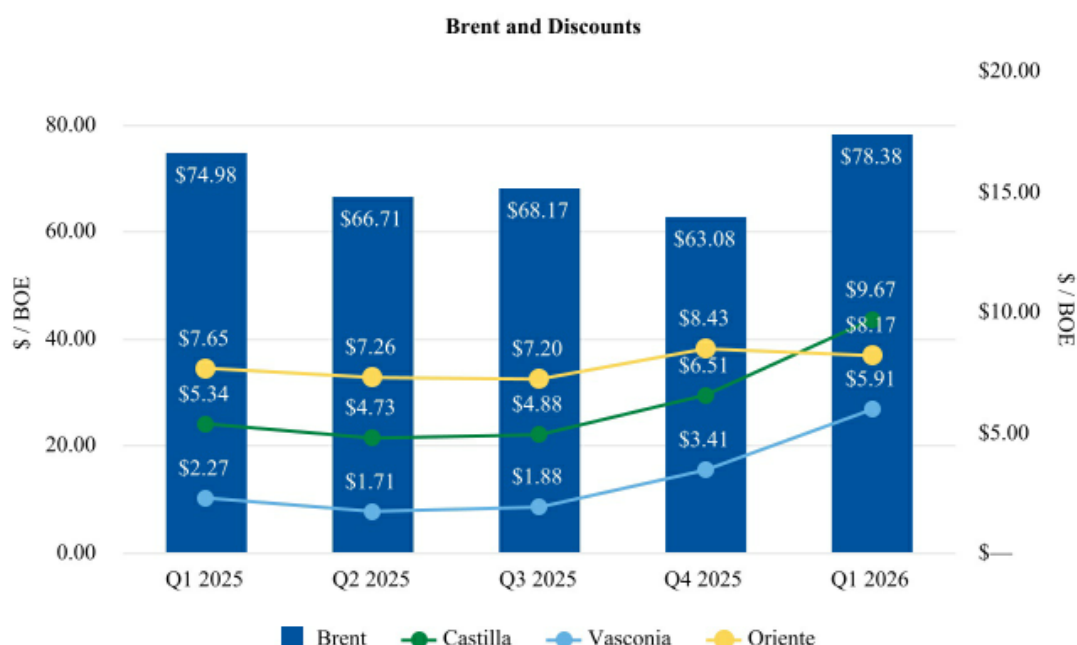
The Midas Block includes the Acordionero field, the Suroriente Block includes the Cohembi field, and the Chaza Block includes the Costayaco and Moqueta fields. Ecuador includes the Charapa, Iguana, Chanangue and Perico Blocks. Canada includes several areas in the Western Canadian Sedimentary Basin with the majority of production in Alberta, Canada.

Commodity prices:

Colombia and Ecuador

Brent - For the three months ended March 31, 2026, Brent increased 5% from the corresponding period of 2025 and increased 24% from the prior quarter. For the three months ended March 31, 2026, Castilla, Vasconia and Oriente differentials per boe increased to \$9.67, \$5.91 and \$8.17 compared to \$5.34, \$2.27 and \$7.65, respectively, in the corresponding period of 2025. Additionally, the realized price for South America was effected by higher transportation discounts. Higher transportation discounts were incurred due to utilizing alternative transportation route associated with Putumayo production in Colombia which was significantly more expensive and resulted in approximately \$4.1 million for the current quarter.

During the three months ended March 31, 2026, 100% of sales from South America was priced against Brent.



Canada

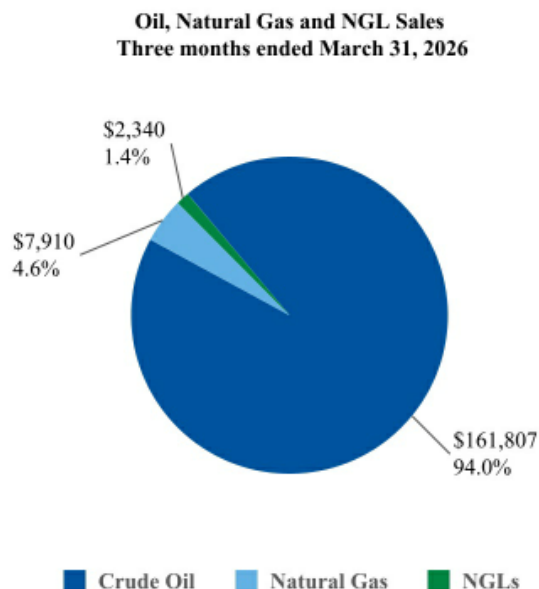
WTI - For the three months ended March 31, 2026, WTI increased 2% from the corresponding period of 2025 and increased 23% from the prior quarter. During the first quarter of 2026, 25% of NAR production in Canada was oil, compared to 21% for the comparable period of 2025, and 26% for the prior quarter.

NGLs - For the three months ended March 31, 2026, the weighted average NGL price received was 10% of WTI compared to 14% percent of WTI in the comparable period of 2025 and 22% percent of WTI in the prior quarter. During the first quarter of 2026, 26% of production in Canada were NGLs, compared to 27% from the comparable period of 2025 and 24% in the prior quarter.

AECO - For the three months ended March 31, 2026, AECO price decreased 7% and 9% from the comparable period of 2025 and from prior quarter, respectively. During the first quarter of 2026, 49% of production in Canada was natural gas, compared to 52% from the comparable period of 2025 and 50% in the prior quarter.

Oil, natural gas and NGL sales for the three months ended March 31, 2026, increased by 2% to \$172.1 million compared to the corresponding period of 2025 due to 3% higher sales volumes driven by selling production from newly acquired Perico Block in Ecuador and 5% increase in Brent price, offset by higher quality and transportation discounts in Colombia. Higher quality and transportation discounts incurred due to using alternative transportation route associated with Putumayo production which was significantly more expensive and resulted in approximately \$4.1 million for the current quarter.

Compared to the prior quarter, oil, natural gas and NGL sales increased by 32%, primarily due to a 24% increase in Brent price, and a 12% increase in sales volumes as a result of higher sales volumes in Ecuador partially offset by higher differentials. During the first quarter, we had two liftings in Ecuador compared to one in prior quarter. The sales price in Ecuador is the average Brent price less discounts for the month prior to lifting (M-1). During the three months ended March 31, 2026, we sold our January 2026 production for the average Brent price of December 2025 and the March 2026 production at the average Brent price of February 2026.



The following table shows the effect of changes in realized price and sale volumes on our oil sales for the three months ended March 31, 2026, compared to the prior quarter and the corresponding period of 2025:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2026, Compared with Three Months Ended December 31, 2025	Three Months Ended March 31, 2026, Compared with Three Months Ended March 31, 2025
Oil, natural gas and NGL sales for the comparative period	\$ 129,929	\$ 168,173
Realized sales price increase (decrease) effect	29,822	(1,471)
Sales volumes increase effect	12,306	5,355
Oil, natural gas and NGL sales for the three months ended March 31, 2026	\$ 172,057	\$ 172,057

Gross Profit

Colombia (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 102,324	\$ 117,648	\$ 89,072
Operating expenses	35,042	42,490	39,897
Transportation expenses	2,272	3,211	2,657
Depletion and accretion ^(*)	40,633	44,999	49,383
Gross profit (loss)	\$ 24,377	\$ 26,948	\$ (2,865)

^(*) Calculated as DD&A expenses for the three months ended March 31, 2026 and 2025 of \$46.4 million and \$48.7 million less depreciation of administrative assets of \$5.7 million and \$3.7 million, respectively. For the prior quarter, calculated as DD&A expenses of \$53.3 million, less depreciation of administrative assets of \$3.9 million.

Colombia (U.S. Dollars per boe Sales NAR)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 60.19	\$ 62.69	\$ 50.07
Operating expenses	20.61	22.64	22.43
Transportation expenses	1.34	1.71	1.49
Depletion and accretion	23.90	23.98	27.76
Gross profit (loss)	\$ 14.34	\$ 14.36	\$ (1.61)

Ecuador (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 40,745	\$ 21,023	\$ 12,486
Operating expenses	15,952	8,073	2,918
Transportation expenses	2,554	1,093	632
Depletion and accretion ^(*)	15,861	10,496	5,258
Gross profit	\$ 6,378	\$ 1,361	\$ 3,678

^(*) Calculated as DD&A expenses for the three months ended March 31, 2026 and 2025 of \$16.0 million and \$10.5 million less depreciation of administrative assets of \$0.1 million and nil, respectively. For the prior quarter, calculated as DD&A expenses of \$5.5 million, less depreciation of administrative assets of \$0.3 million.

Ecuador (U.S. Dollars per boe Sales NAR)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 57.30	\$ 67.71	\$ 56.52
Operating expenses	22.43	26.00	13.21
Transportation expenses	3.59	3.52	2.86
Depletion and accretion	22.30	33.81	23.80
Gross profit	\$ 8.98	\$ 4.38	\$ 16.65

Canada (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 28,988	\$ 29,502	\$ 28,371
Operating expenses	15,155	16,527	14,345
Transportation expenses	477	247	393
Depletion and accretion ^(*)	7,414	12,936	13,595
Gross profit (loss)	\$ 5,942	\$ (208)	\$ 38

^(*) Same as DD&A expenses for the three months ended March 31, 2026 and 2025 and the prior quarter.

Canada (U.S. Dollars per boe Sales NAR)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 23.90	\$ 22.27	\$ 21.65
Operating expenses	12.49	12.47	10.95
Transportation expenses	0.39	0.19	0.30
Depletion and accretion	6.11	9.76	10.37
Gross profit (loss)	\$ 4.91	\$ (0.15)	\$ 0.03

Total Company (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 172,057	\$ 168,173	\$ 129,929
Operating expenses	66,149	67,090	57,160
Transportation expenses	5,303	4,551	3,682
Depletion and accretion ^(*)	63,908	68,431	68,236
Gross profit	\$ 36,697	\$ 28,101	\$ 851

^(*) Calculated as DD&A expenses for the three months ended March 31, 2026 and 2025 of \$69.9 million and \$72.2 million less depreciation of administrative assets of \$6.0 million and \$3.8 million, respectively. For the prior quarter, calculated as DD&A expenses of \$72.5 million, less depreciation of administrative assets of \$4.3 million.

Total Company (U.S. Dollars per boe Sales NAR)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Revenue	\$ 47.48	\$ 47.88	\$ 39.25
Operating expenses	18.25	19.10	17.27
Transportation expenses	1.46	1.30	1.11
Depletion and accretion	17.63	19.48	20.61
Gross profit	\$ 10.14	\$ 8.00	\$ 0.26

Operating Netback

Colombia (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
			2025
Oil, natural gas and NGL sales	\$ 102,324	\$ 117,648	\$ 89,072
Transportation expenses	(2,272)	(3,211)	(2,657)
	100,052	114,437	86,415
Operating expenses	(35,042)	(42,490)	(39,897)
Operating netback ⁽¹⁾	\$ 65,010	\$ 71,947	\$ 46,518

(U.S. Dollars Per boe Sales Volumes NAR)

Brent	\$ 78.38	\$ 74.98	\$ 63.08
Quality and transportation discounts	(18.19)	(12.29)	(13.01)
Average realized price	60.19	62.69	50.07
Transportation expenses	(1.34)	(1.71)	(1.49)
Average realized price net of transportation expenses	58.85	60.98	48.58
Operating expenses	(20.61)	(22.64)	(22.43)
Operating netback ⁽¹⁾	\$ 38.24	\$ 38.34	\$ 26.15

Ecuador (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
			2025
Oil, natural gas and NGL sales	\$ 40,745	\$ 21,023	\$ 12,486
Transportation expenses	(2,554)	(1,093)	(632)
	38,191	19,930	11,854
Operating expenses	(15,952)	(8,073)	(2,918)
Operating netback ⁽¹⁾	\$ 22,239	\$ 11,857	\$ 8,936

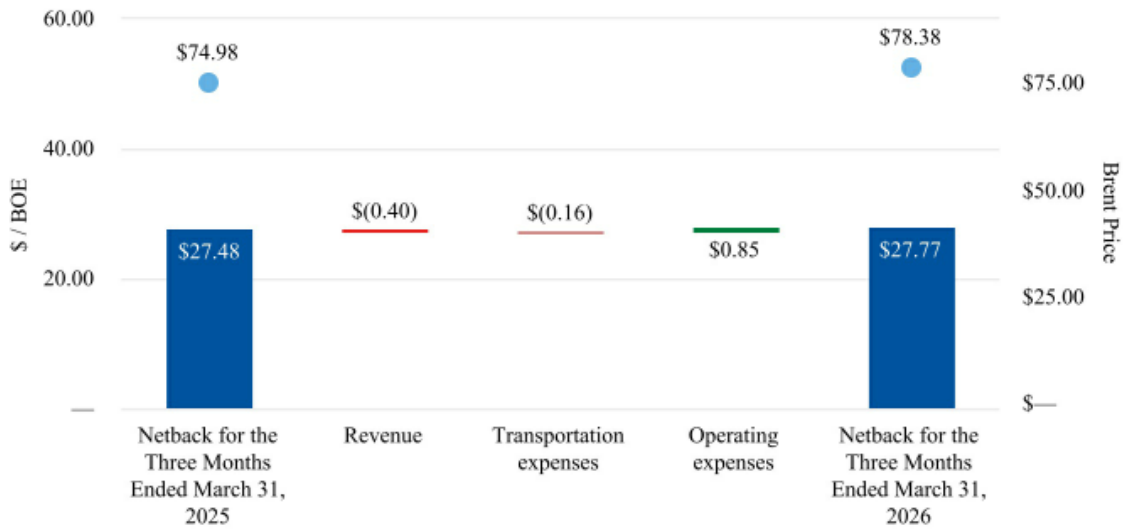
(U.S. Dollars Per boe Sales Volumes NAR)

Brent (M-1 Pricing)	\$ 65.12	\$ 75.53	\$ 65.09
Quality and transportation discounts	(7.82)	(7.82)	(8.57)
Average realized price	57.30	67.71	56.52
Transportation expenses	(3.59)	(3.52)	(2.86)
Average realized price net of transportation expenses	53.71	64.19	53.66
Operating expenses	(22.43)	(26.00)	(13.21)
Operating netback ⁽¹⁾	\$ 31.28	\$ 38.19	\$ 40.45

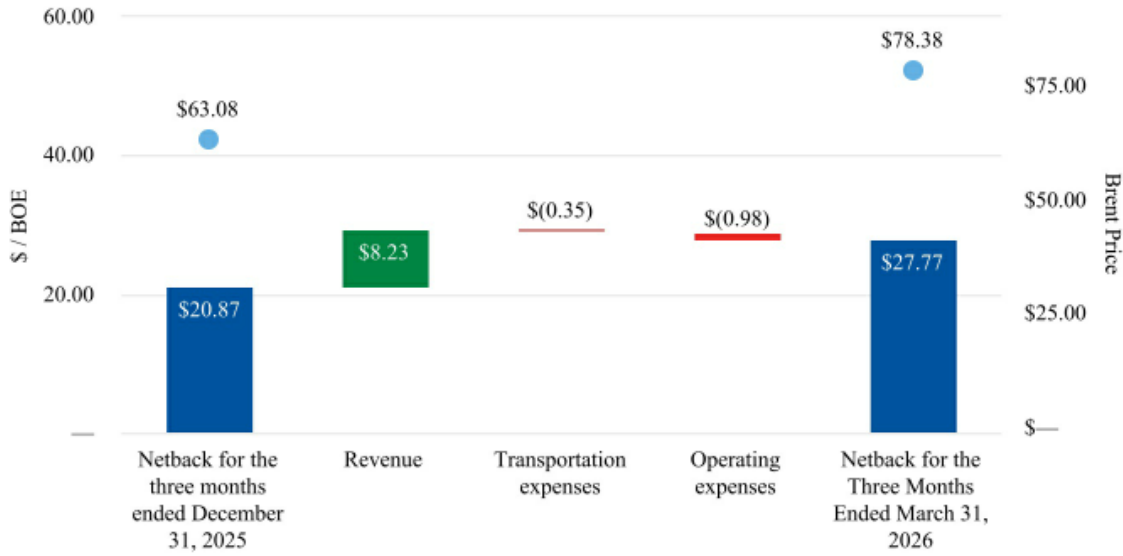
Canada (Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Oil, natural gas and NGL sales	\$ 28,988	\$ 29,502	\$ 28,371
Transportation expenses	(477)	(247)	(393)
	<u>28,511</u>	<u>29,255</u>	<u>27,978</u>
Operating expenses	(15,155)	(16,527)	(14,345)
Operating netback ⁽¹⁾	<u>\$ 13,356</u>	<u>\$ 12,728</u>	<u>\$ 13,633</u>
(U.S. Dollars Per boe Sales Volumes NAR)			
WTI Price per bbl	\$ 72.73	\$ 71.47	\$ 59.24
AECO Price C\$ per GJ	1.91	2.05	2.11
Average realized price	23.90	22.27	21.65
Transportation expenses	(0.39)	(0.19)	(0.30)
Average realized price net of transportation expenses	<u>23.51</u>	<u>22.08</u>	<u>21.35</u>
Operating expenses	(12.49)	(12.47)	(10.95)
Operating netback ⁽¹⁾	<u>\$ 11.02</u>	<u>\$ 9.61</u>	<u>\$ 10.40</u>
Total Company			
(Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Oil, natural gas and NGL sales	\$ 172,057	\$ 168,173	\$ 129,929
Transportation expenses	(5,303)	(4,551)	(3,682)
	<u>166,754</u>	<u>163,622</u>	<u>126,247</u>
Operating expenses	(66,149)	(67,090)	(57,160)
Operating netback ⁽¹⁾	<u>\$ 100,605</u>	<u>\$ 96,532</u>	<u>\$ 69,087</u>
(U.S. Dollars Per boe Sales Volumes NAR)			
Average realized price	47.48	47.88	39.25
Transportation expenses	(1.46)	(1.30)	(1.11)
Average realized price net of transportation expenses	<u>46.02</u>	<u>46.58</u>	<u>38.14</u>
Operating expenses	(18.25)	(19.10)	(17.27)
Operating netback ⁽¹⁾	<u>\$ 27.77</u>	<u>\$ 27.48</u>	<u>\$ 20.87</u>

⁽¹⁾ Operating netback is a non-GAAP measure that does not have any standardized meaning prescribed under GAAP. Refer to note 2 "Non-GAAP measures" in "Financial and Operational Highlights" for a definition and reconciliation of this measure.

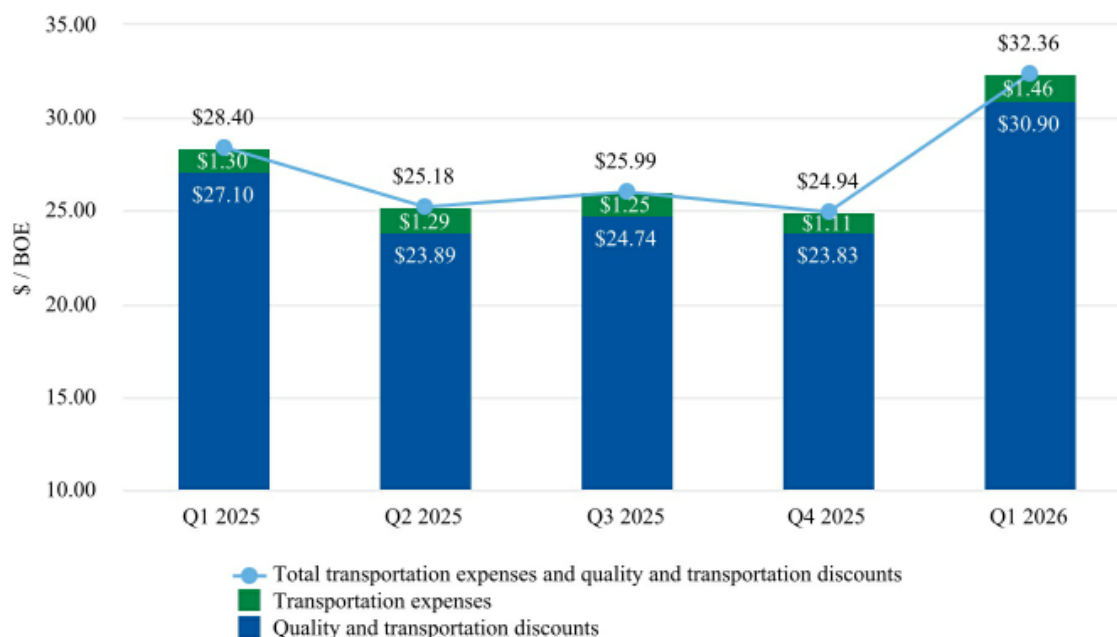
Change in Operating Netback from Q1 2025 to Q1 2026



Change in Operating Netback from Q4 2025 to Q1 2026



Quality and Transportation Discounts and Transportation Expenses



Operating expenses for the three months ended March 31, 2026, decreased by 1% to \$66.1 million compared to the corresponding period of 2025 due to lower workover activities, lower power generation and field personnel costs associated with head count optimization partially offset by higher inventory fluctuations due to the sale of oil inventory accumulated at the end of the previous quarter.

On a per boe basis, operating expenses decreased by \$0.85 to \$18.25 compared to the corresponding period of 2025, primarily due to \$1.14 per boe lower workover activities which were partially offset by \$0.21 per boe higher lifting costs associated with inventory fluctuations.

Compared to the prior quarter, operating expenses increased by 16% from \$57.2 million or by \$0.98 from \$17.27 on a per boe basis primarily a result of inventory fluctuations due to the sale of oil inventory accumulated at the end of the previous quarter partially offset by lower workover activities and lower operating costs across various categories.

Transportation expenses

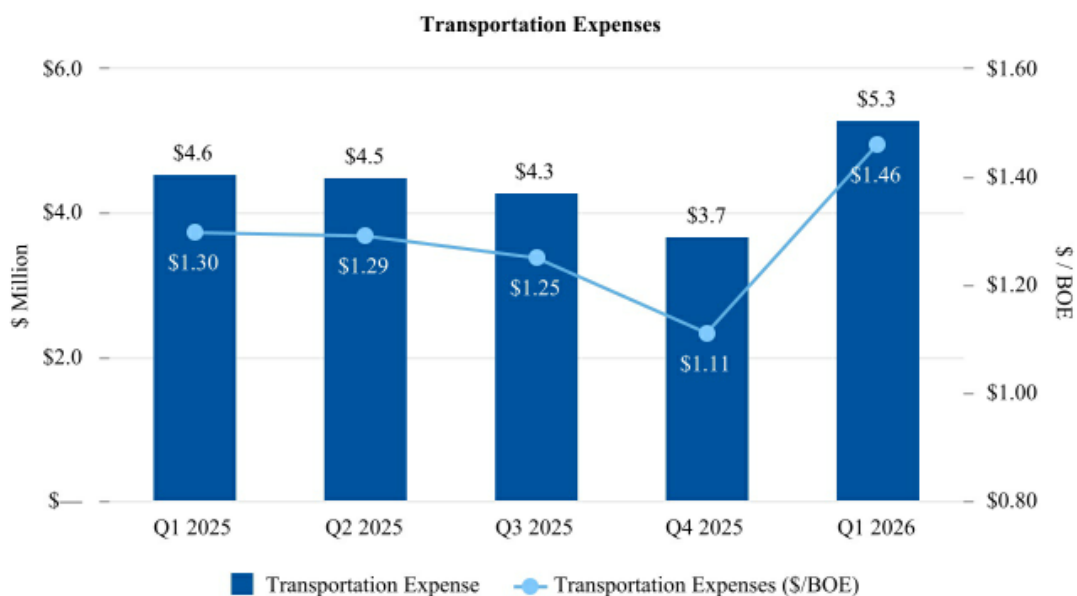
We have options to sell our oil through multiple pipelines and various trucking routes. Each option has varying effects on realized sales price and transportation expenses. The following table shows the percentage of oil, natural gas and NGL volumes we sold in Canada, Colombia and Ecuador using each option for the three months ended March 31, 2026 and 2025, and the prior quarter:

	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31, 2025
Volume transported through pipeline	54 %	46%	46%
Volume sold at wellhead	24 %	25%	28%
Volume transported via truck to sales point	22 %	29%	26%
	100 %	100%	100%

Volumes transported through pipeline or via truck receive a higher realized price but incur higher transportation expenses. Conversely, volumes sold at the wellhead have the opposite effect of a lower realized price, offset by lower transportation expenses.

Transportation expenses for the three months ended March 31, 2026, increased by 17% to \$5.3 million or \$0.16 to \$1.46 per boe, compared to the corresponding period of 2025, due to higher sales volumes transported in Ecuador during the current quarter.

Transportation expenses increased by 44% or \$0.35 per boe from \$3.7 million or \$1.11 per boe in the prior quarter for the same reason mentioned above.



Colombia (U.S. Dollars per boe Sales Volumes NAR)	Three Months Ended March 31, 2026, Compared with Three Months Ended December 31, 2025	Three Months Ended March 31, 2026, Compared with Three Months Ended March 31, 2025
Average Brent price	\$ 78.38	\$ 78.38
Average realized price, net of transportation expenses for the comparative period	\$ 48.58	\$ 60.98
Increase in benchmark prices	15.30	3.40
Increase in quality and transportation discounts	(5.18)	(5.90)
Decrease in transportation expense	0.15	0.37
Average realized price, net of transportation expenses for the period	<u>\$ 58.85</u>	<u>\$ 58.85</u>
Average realized price, net of transportation expenses as a % of Brent	75 %	75%

Ecuador (U.S. Dollars per boe Sales Volumes NAR)	Three Months Ended March 31, 2026, Compared with Three Months Ended December 31, 2025	Three Months Ended March 31, 2026, Compared with Three Months Ended March 31, 2025
Average Brent price (M-1 Pricing)	\$ 65.12	\$ 65.12
Average realized price, net of transportation expenses for the comparative period	\$ 53.66	\$ 64.19
Increase (decrease) in benchmark prices	0.03	(10.41)
Decrease in quality and transportation discounts	0.75	-
Increase in transportation expense	(0.73)	(0.07)
Average realized price, net of transportation expenses for the period	<u>\$ 53.71</u>	<u>\$ 53.71</u>
Average realized price, net of transportation expenses as a % of Brent	82 %	82%

Canada (U.S. Dollars per boe Sales Volumes NAR)	Three Months Ended March 31, 2026, Compared with Three Months Ended December 31, 2025	Three Months Ended March 31, 2026, Compared with Three Months Ended March 31, 2025
Average WTI price	\$ 72.73	\$ 72.73
Average AECO price	\$ 1.91	\$ 1.91
Average realized price, net of transportation expenses for the comparative period	\$ 21.35	\$ 22.08
Increase in benchmark prices	13.49	1.26
(Increase) decrease in quality and transportation discounts	(11.24)	0.37
Increase in transportation expense	(0.09)	(0.20)
Average realized price, net of transportation expenses for the period	<u>\$ 23.51</u>	<u>\$ 23.51</u>
Average realized price, net of transportation expenses as a % of WTI	32 %	32%

Total Company (U.S. Dollars per boe Sales Volumes NAR)	Three Months Ended March 31, 2026, Compared with Three Months Ended December 31, 2025	Three Months Ended March 31, 2026, Compared with Three Months Ended March 31, 2025
Average Brent price	\$ 78.38	\$ 78.38
Average realized price, net of transportation expenses for the comparative period	\$ 38.14	\$ 46.58
Increase in benchmark prices	15.30	3.40
Increase in quality and transportation discounts	(7.07)	(3.80)
Increase in transportation expense	(0.35)	(0.16)
Average realized price, net of transportation expenses for the period	<u>\$ 46.02</u>	<u>\$ 46.02</u>
Average realized price, net of transportation expenses as a % of Brent	59 %	59%

DD&A Expenses

	Three Months Ended March 31,		Three Months Ended
	2026	2025	December 31,
DD&A Expenses, thousands of U.S. Dollars	\$ 69,874	\$ 72,202	\$ 72,535
DD&A Expenses, U.S. Dollars per boe	19.28	20.56	21.91

	Three Months Ended March 31, 2026		Three Months Ended March 31, 2025		Three Months Ended December 31, 2025	
	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, U.S. Dollars Per Boe	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, U.S. Dollars Per Boe	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, U.S. Dollars Per Boe
Colombia	\$ 46,378	\$ 27.28	\$ 48,651	\$ 25.92	\$ 53,290	\$ 29.95
Ecuador	15,964	22.45	10,498	33.81	5,534	25.05
Canada	7,419	6.12	12,941	9.77	13,600	10.38
Corporate	113	-	112	-	111	-
	<u>\$ 69,874</u>	<u>\$ 19.28</u>	<u>\$ 72,202</u>	<u>\$ 20.56</u>	<u>\$ 72,535</u>	<u>\$ 21.91</u>

DD&A expenses for the three months ended March 31, 2026, decreased by 3% or by \$1.28 on a per boe basis, due to lower costs in the depletable base for Canadian operations as a result of Simonette field disposition and higher proved reserves in Ecuador, compared to the corresponding period of 2025.

DD&A expenses decreased by 4% from \$72.5 million or by \$2.63 on a per boe basis when compared to the prior quarter for the same reason mentioned above.

Asset Impairment

For the three months ended March 31, 2026 and 2025, we had no ceiling test impairment losses. We used a 12-month unweighted average of the first-day-of-the-month prices prior to the ending date of the period ended March 31, 2026 as follows: Brent Crude \$67.58 per boe, Edmonton Light Crude of C\$83.04 per boe, Alberta AECO spot price of C\$1.99 per MMBtu Edmonton Propane C\$28.38 per boe, Edmonton Butane C\$36.04 per boe and Edmonton Condensate C\$85.94 and for the period ended three months ended March 31, 2025 Brent Crude of \$78.90 per boe, Edmonton Light Crude of C\$98.11 per boe, Alberta AECO spot price of C\$1.51 per MMBtu Edmonton Propane C\$32.53 per boe, Edmonton Butane C\$48.81 per boe and Edmonton Condensate C\$101.71.

G&A Expenses

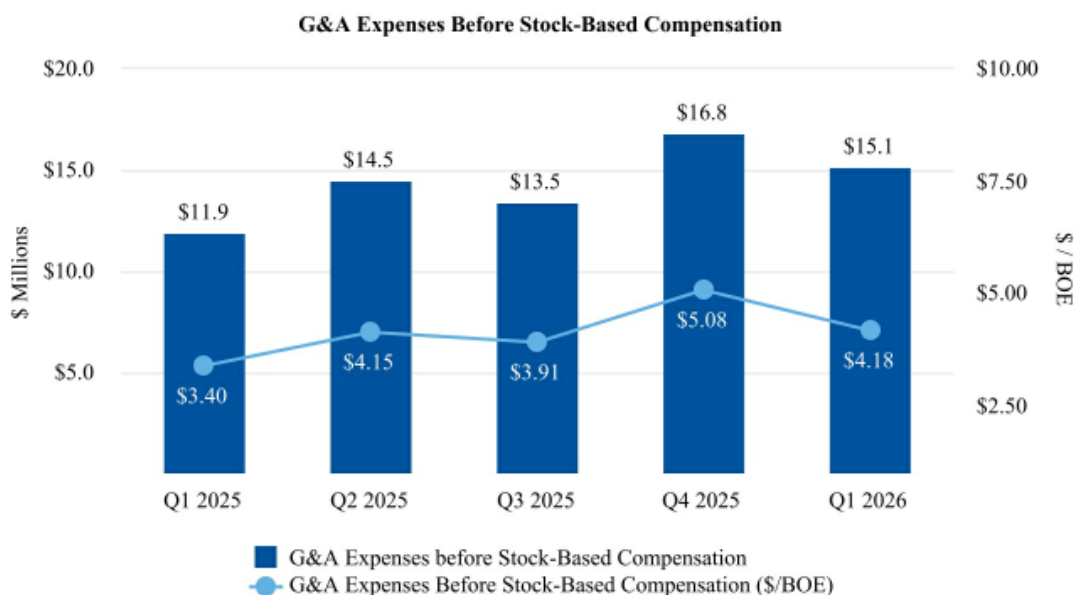
(Thousands of U.S. Dollars)	Three Months Ended March 31,			Three Months Ended
	2026	2025	% Change	December 31, 2025
G&A Expenses before Stock-Based Compensation	\$ 15,149	\$ 11,926	27	\$ 16,817
G&A Stock-Based Compensation Expense (Recovery)	19,676	(517)	3,906	3,042
G&A Expenses, including Stock-Based Compensation	\$ 34,825	\$ 11,409	205	\$ 19,859
(U.S. Dollars Per boe Sales Volumes NAR)				
G&A Expenses before Stock-Based Compensation	\$ 4.18	\$ 3.40	23	\$ 5.08
G&A Stock-Based Compensation Expense (Recovery)	5.43	(0.15)	3,789	0.92
G&A Expenses, including Stock-Based Compensation	\$ 9.61	\$ 3.25	196	\$ 6.00

G&A expenses before stock-based compensation for the three months ended March 31, 2026, increased by 27% to \$15.1 million or by \$0.78 to \$4.18 per boe compared to the corresponding period of 2025, primarily due to higher consulting costs attributable to optimization projects.

Compared to the prior quarter, G&A expenses before stock-based compensation decreased by 10% or \$0.90 per boe due to headcount optimization and higher sales volumes.

G&A expenses after stock-based compensation for the three months ended March 31, 2026, increased by 205% or \$6.36 per boe, compared to the corresponding period of 2025, due to higher stock-based compensation cost attributed to a higher share price during the current quarter.

Compared to the prior quarter, G&A expenses after stock-based compensation increased by 75% or \$3.61 per boe for the same reason mentioned above.

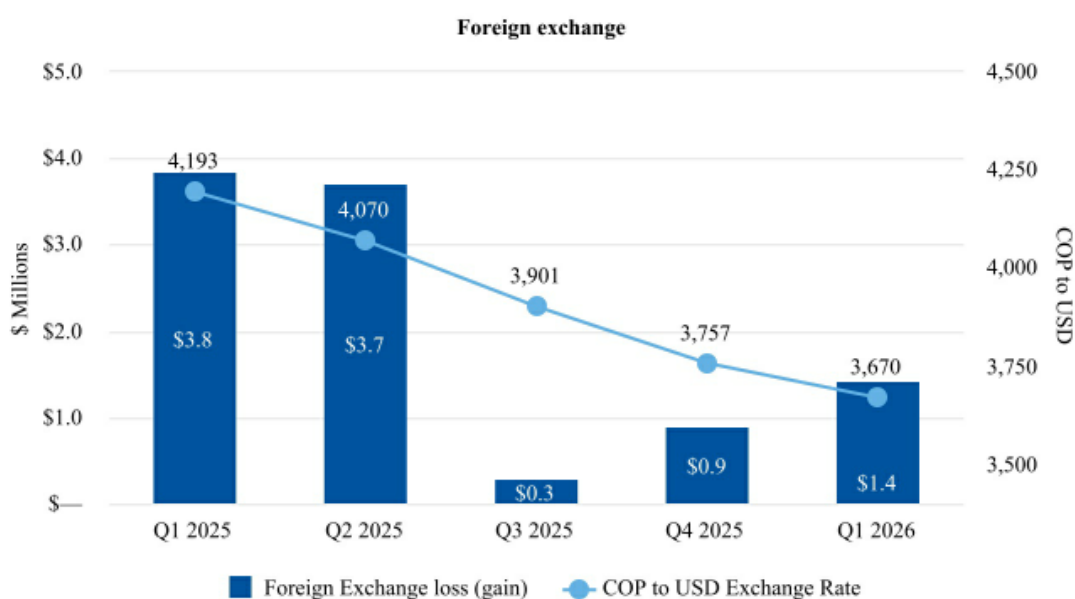


Severance Expenses

For the three months ended March 31, 2026, severance expenses were \$2.5 million, compared to nil for the corresponding period of 2025 and the prior quarter, respectively due to headcount optimization.

Foreign Exchange Gains and Losses

For the three months ended March 31, 2026, we had a \$1.4 million loss on foreign exchange compared to a \$3.8 million loss on foreign exchange in the corresponding period of 2025, and a \$0.9 million loss on foreign exchange in the prior quarter. Accounts payable, taxes receivable and payable and deferred income taxes are considered monetary items and require translation from local currencies to U.S. dollar functional currency at each balance sheet date. This translation was the primary source of the foreign exchange gains and losses in the periods.



The following table presents the change in the U.S. dollar against the Colombian peso and Canadian dollar for the three months ended March 31, 2026 and 2025 and the prior quarter:

	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Change in the U.S. dollar against the Colombian peso	weakened by 2 %	weakened by 5%	weakened by 4%
Change in the U.S. dollar against the Canadian dollar	strengthened by 1 %	weakened by -%	weakened by 1%

Financial Instruments Gains or Losses

The following table presents the nature of our financial instruments gains or losses three months ended March 31, 2026 and 2025, and the prior quarter:

(Thousands of U.S. Dollars)	Three Months Ended March 31,		Three Months Ended December 31,
	2026	2025	2025
Commodity price derivative loss (gain)	\$ 88,618	\$ 1,467	\$ (8,482)
Foreign currency derivative gain	(208)	-	-
Electricity price derivative loss	-	-	56
Derivative instruments loss (gain)	\$ 88,410	\$ 1,467	\$ (8,426)

Income Tax Expense

(Thousands of U.S. Dollars)	Three Months Ended March 31,	
	2026	2025
Loss before income tax	\$ (145,767)	\$ (15,727)
Current income tax expense	\$ 5,850	\$ 8,265
Deferred income tax recovery	(32,445)	(4,712)
Income tax (recovery) expense	\$ (26,595)	\$ 3,553
Effective tax rate	18 %	(23)%

Current income tax expense was \$5.9 million for the three months ended March 31, 2026, compared to \$8.3 million in the corresponding period of 2025, primarily due to lower taxable income.

The deferred tax for the three months ended March 31, 2026, was a recovery of \$32.4 million mainly due to an increase in deductible temporary differences arising from tax losses generated during the period and accruals. These were partially offset by higher tax depreciation relative to accounting depreciation.

The deferred income tax for the three months ended March 31, 2025, was a recovery of \$4.7 million mainly due to the use of a higher enacted tax rate on Colombia tax losses. These were partially offset by higher tax depreciation relative to accounting depreciation.

For the three months ended March 31, 2026, the difference between the effective tax rate of 18% and the 21% statutory tax rate was primarily due to an increase in the non-deductible foreign translation adjustments and other permanent differences. This was partially offset by an increase in the impact of foreign taxes.

For the three months ended March 31, 2025, the difference between the effective tax rate of negative 23% and the 21% statutory tax rate was primarily due to an increase in the non-deductible foreign translation adjustments, other permanent differences and valuation allowance. This was partially offset by an increase in the impact of foreign taxes.

Net (Loss) Income and Funds Flow from Operations (a Non-GAAP Measure)

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2026, Compared with Three Months Ended December 31, 2025	% change	Three Months Ended March 31, 2026, Compared with Three Months Ended March 31, 2025	% change
Net loss for the comparative period	\$ (141,148)		\$ (19,280)	
Increase (decrease) due to:				
Sales price	29,822		(1,471)	
Sales volumes	12,306		5,355	
Expenses:				
Cash operating expenses	(8,989)		941	
Transportation	(1,621)		(752)	
Other taxes	(384)		(560)	
Cash G&A, excluding stock-based compensation expense	1,668		(3,223)	
Net lease payments	(105)		(388)	
Severance	(2,468)		(2,468)	
Interest, excluding amortization of deferred financing fees	308		(1,767)	

Realized foreign exchange loss	1,167	526		
Other gain	420	420		
Cash settlement on derivative instruments	(11,839)	(11,525)		
Current taxes	(4,473)	2,415		
Interest income	184	(24)		
Net change in funds flow from operations⁽¹⁾ from comparative period	15,996	(12,521)		
Expenses:				
Depletion, depreciation and accretion	2,661	2,328		
Asset impairment	136,261	-		
Deferred tax	(5,610)	27,733		
Amortization of debt issuance costs	(6,534)	(7,460)		
Stock-based compensation	(16,634)	(20,193)		
Senior Notes exchange fees	(12,903)	(12,903)		
Non-cash interest	(2,488)	(4,513)		
Financial instruments loss, net of financial instruments settlements	(84,997)	(75,418)		
Unrealized foreign exchange (loss) gain	(1,696)	1,887		
Other non-cash (loss) gain	(2,185)	780		
Net lease payments	105	388		
Net change in net loss	21,976	(99,892)		
Net loss for the current period	\$ (119,172)	16 %	\$ (119,172)	(518)%

⁽¹⁾ Funds flow from operations is a non-GAAP measure that does not have any standardized meaning prescribed under GAAP. Refer to note 2 "Non-GAAP measures" in "Financial and Operational Highlights" for a definition and reconciliation of this measure.

Capital expenditures during the three months ended March 31, 2026, were \$45.4 million.

(Millions of U.S. Dollars)	Colombia	Ecuador	Canada	Total
Exploration:				
Drilling and Completions	\$ 0.5	\$ 0.8	\$ -	1.3
Civil Works	0.2	-	-	0.2
Other	2.5	1.4	-	3.9
Total Exploration	\$ 3.2	\$ 2.2	\$ -	5.4
Development:				
Drilling and Completions	\$ 13.8	\$ 0.2	\$ 4.0	18.0
Facilities	7.6	0.8	-	8.4
Civil Works	2.0	-	1.4	3.4
Other	8.2	2.0	-	10.2
Total Development	\$ 31.6	\$ 3.0	\$ 5.4	40.0
Total Company	\$ 34.8	\$ 5.2	\$ 5.4	45.4

During the three months ended March 31, 2026, we drilled the following wells:

	Number of wells (Gross)	Number of wells (Net)
Development - Colombia	3	1.4
Development - Canada	3	1.5
Total Company	6	2.9

During the three months ended March 31, 2026, we spud three development wells in Colombia and three in Canada. As of March 31, 2026, two development wells drilled in Colombia were producing and one well was in-progress. The wells drilled in Canada were in Simonette area, which was disposed during the three months ended March 31, 2026.

Liquidity and Capital Resources

(Thousands of U.S. Dollars)	As at		
	March 31, 2026	% Change	December 31, 2025
Cash and Cash Equivalents	\$ 124,752	50	\$ 82,931
7.75% Senior Notes due 2027	\$ 24,201	-	\$ 24,201
9.50% Senior Notes due 2029	\$ 87,639	(88)	\$ 716,340
9.75% Senior Notes due 2031	\$ 494,353	100	\$ -

We believe that our capital resources, including cash on hand and cash generated from operations will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for the next 12 months, given the current oil price trends and production levels. We may also access capital markets to pursue financing, including for the re-purchase of common stock or the repayment of debt in the future. In accordance with our investment policy, available cash balances are held in our primary cash management banks or may be invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us with the flexibility to respond to both internal growth opportunities and those available through acquisitions. We intend to pursue growth opportunities and acquisitions from time to time, which may require significant capital to be located in basins or countries beyond our current operations, involve joint ventures, or be sizable compared to our current assets and operations.

Senior Notes

During the three months ended March 31, 2026, we issued \$503.6 million in aggregate principal amount of its 9.75% Senior Secured Amortizing Notes due 2031 (the "9.75% Senior Notes"), and paid \$125.0 million in cash consideration in exchange for \$628.7 million aggregate principal amount of its 9.50% Senior Secured Amortizing Notes due 2029 (the "9.50% Senior Notes"). The exchange was accounted for as debt modification.

The 9.75% Senior Notes will mature on April 15, 2031, unless earlier redeemed or re-purchased. The principal amount of 9.75% Senior Notes is to be repaid as follows: (i) October 15, 2029 - 15% of the principal amount; (ii) October 15, 2030 - 15% of the principal amount; (iii) April 15, 2031 - the remainder of the principal amount. We are required to complete mandatory redemption of \$30.0 million aggregate principal amount of 9.75% Senior Notes less any re-purchases in the open market during the year ended December 31, 2026.

At any time, prior to April 15, 2028, we may redeem up to 0.35 of the aggregate principal amount of 9.75% Senior Notes at a redemption price equal to 1.0975 of the principal amount. Additionally, we may redeem all or a portion of the 9.75% Senior Notes on or after 2028 at the following redemption prices: 2028 - 1.04875; 2029 - 1.02438; 2030 and thereafter - 1.

Under the terms of the 9.75% Senior Notes agreement, we are required to maintain compliance with the following financial covenants:

- i. consolidated interest coverage ratio of not less than 2.50; and
- ii. consolidated net debt (total debt excluding deferred financing fees debt less cash equivalents) to consolidated adjusted earnings before interest, taxes and DD&A ("EBITDA") of not more than 3.00.

During the three months ended March 31, 2026, we re-purchased \$9.2 million of 9.75% Senior Notes for cash consideration of \$8.1 million resulting in a \$0.6 million gain on purchase, which included the write-off of deferred financing fees of \$0.5 million.

As at March 31, 2026, we were in compliance with all applicable covenants related to Senior Notes.

Credit Facility

As at March 31, 2026, we, through our wholly owned subsidiary Gran Tierra Canada Ltd., had a revolving credit facility with National Bank of Canada with a borrowing base of C\$100.0 million (US\$71.9 million) and the available commitment of a C\$75.0 million (US\$54.0 million) revolving credit facility comprised of C\$60.0 million (US\$43.2 million) syndicated facility and C\$15.0 million (US\$10.8 million) of operating facility. The drawn down amounts under the revolving credit facility can either be in Canadian or U.S. dollars and bear interest rates equal to either the Canadian prime rate or U.S. Base Rate plus a margin ranging from 2.00% to 4.00% per annum or for CORRA loans and SOFR loans plus a margin ranging from 3.00% to 5.00% per annum. Undrawn amounts under the revolving credit facility bear standby fee ranging from 0.75% to 1.25% per annum. In each case, the margin or standby fee, as applicable is based on Net Debt to EBITDA ratio of Gran Tierra Canada Ltd. The revolving credit facility matures on October 30, 2027. As of March 31, 2026, the revolving credit facility remained undrawn.

Prepayment agreements

During the three months ended March 31, 2026, we amended our existing prepayment agreement with Trafigura, entering into a new oil prepayment agreement that covers both our Ecuadorian and Colombian oil production. The amended agreement provides for a total prepayments of up to \$350.0 million, including \$325.0 million available immediately and additional \$25.0 million available at Trafigura's sole discretion. The term of the amended prepayment agreement is 48 months.

Amounts drawn on this prepayment agreement are to be repaid through future oil deliveries. Shortfalls in crude oil deliveries in any given repayment period can be delivered during the next repayment period within three calendar months or paid in cash thereafter. Amounts under the prepayment facility are subject to interest based on SOFR risk-free rate plus a margin of 4.45% per annum. Under the terms of the prepayment agreement, we can repay the outstanding balance of the advance payment at any time without penalty. We were granted a six-month grace period for repayment of the principal amount drawn under the prepayment agreement with first re-payment starting April 2026.

Pursuant to the amended and restated prepayment agreement, proceeds from the new advance are required to be used exclusively to finance the repurchase or exchange of Senior Notes and to pay fees and expenses associated with the amended agreement.

We are required to maintain compliance with the following financial covenants related to amounts drawn under the prepayment agreement semi-annually, calculated on March 31 and September 30 of each year:

- i. Asset Coverage Ratio of at least 150%, calculated using the net present value of the consolidated future cash flows of certain wholly owned subsidiaries of the Company that sell crude oil, projected through the final maturity date and discounted at 10% over the outstanding principal and the interest payable amount on the prepayment agreement at each reporting period. The net present value of the consolidated future cash flows of the Company is required to be based on 90% of the prevailing ICE Brent forward strip.
- ii. Debt Service Coverage Ratio of at least 200%, calculated using the estimated crude oil to be delivered by the Company from any relevant time up to the final maturity date based on 80% of the prevailing ICE Brent forward strip and adjusted for quality differential and transportation discount over the outstanding principal amount under the prepayment agreement.

As at March 31, 2026, there was \$316.5 million outstanding under the oil prepayment agreement. Of this amount, \$86.3 million was classified as a current portion and included in accounts payable and accrued liabilities balance on the Company's Condensed Consolidated Balance Sheet.

Disposition of Simonette area

During the three months ended March 31, 2026, we disposed of the entire working interest and associated title rights in the Simonette Montney area in Canada effective January 1, 2026, for total cash consideration of C\$66.3 million (US\$48.6 million). The consideration comprised of C\$50.0 million (US\$36.6 million) attributable to the sale of crude oil and natural gas rights, C\$12.5 million (US\$9.2 million) related to the sale of tangible assets and seismic data and economic rights adjustment to effective date of (US\$2.8 million). No gain or loss was recognized in the statement of operations because the disposal did not materially change the relationship between capital costs and the proved reserves of oil and natural gas assets.

Partnership with Ecopetrol S.A.

During the first quarter, we entered into a strategic partnership with Ecopetrol S.A. to earn, subject to regulatory approvals and conditions precedent, a 49% WI in the Tisquirama Block in Colombia. Under the terms of the agreement, we have committed to fund approximately \$47.1 million of a \$92.4 million gross capital program over 40 months, including a minimum Phase 1 investment of \$15.0 million. Upon completion of Phase 1, we will be entitled to 49% of production and is expected to assume operatorship. The effective date of the Contract is subject to regulatory approval.

Production sharing agreement (“PSA”)

During the first quarter, we, through our wholly owned subsidiary, Gran Tierra Energy (Azerbaijan) GmbH, entered into an exploration, development and PSA with the State Oil Company of Azerbaijan Republic (“SOCAR”), providing for a 65% participating interest to us and a 35% participating interest to SOCAR. The PSA provides for a five-year exploration phase and, in the event of a commercial crude oil discovery, a 25-year development phase, with minimum work commitments during the exploration period to be completed within 36 months. These commitments include, among others, the acquisition of 250 square kilometers of 3D seismic data, the drilling of two exploration wells, and the conduct of geological and environmental impact studies. We have the right to relinquish the entire contract area during the exploration phase upon fulfillment of its exploration commitments, subject to 90 days’ prior notice to SOCAR.

Derivative positions

As at March 31, 2026, we had outstanding commodity price derivative positions as follows:

Oil

Type of Instrument	Start Period	End Period	Volume bbl/d	Reference	Sold Put (C\$/bbl or \$/bbl Weighted Average)	Purchased Put (C\$/bbl or \$/bbl Weighted Average)	Sold Call (C\$/bbl or \$/bbl Weighted Average)	Premium (C\$/bbl or \$/bbl Weighted Average)
3 Way Collar	April 01, 2026	June 30, 2026	11,500	Brent	48.26	58.48	72.03	-
3 Way Collar	April 01, 2026	June 30, 2026	1,000	WTI CMA	C\$ 62.50	C\$ 72.50	C\$ 103.70	C\$ 0.95
Call Option	April 01, 2026	June 30, 2026	4,500	Brent	-	-	102.22	9.96
Call Option	April 01, 2026	June 30, 2026	500	WTI CMA	-	-C\$	130.00	C\$ 13.45
Put Option	April 01, 2026	June 30, 2026	2,500	Brent	-	64.00	-	4.06
3 Way Collar	July 01, 2026	September 30, 2026	14,000	Brent	48.79	58.79	71.35	-
3 Way Collar	July 01, 2026	September 30, 2026	500	WTI CMA	-	60.00	-	4.30
3 Way Collar	July 01, 2026	September 30, 2026	1,000	WTI CMA	C\$ 62.50	C\$ 72.50	C\$ 103.70	C\$ 0.95
3 Way Collar	July 01, 2026	September 30, 2026	500	WTI CMA	-C\$	C\$ 75.00	C\$ 91.95	-
3 Way Collar	October 01, 2026	December 31, 2026	14,000	Brent	48.43	58.43	70.87	-
Put Option	October 01, 2026	December 31, 2026	500	Brent	-	60.00	-	4.30
3 Way Collar	October 01, 2026	December 31, 2026	500	WTI CMA	C\$ 60.00	C\$ 70.00	C\$ 107.00	C\$ 1.90

Collar	October 01, 2026	December 31, 2026	500 WTI CMA	- C\$	70.00 C\$	92.47 C\$	-
3 Way	January 01, 2027	March 31, 2027	3,000 Brent	58.33	71.67	89.55	-

Natural Gas

Type of Instrument	Start Period	End Period	Volume, GJ/day	Reference	Sold Swap (C\$/GJ, Weighted Average)	Purchased Put (C\$/GJ, Weighted Average)	Sold Call (C\$/GJ, Weighted Average)
Swap	April 01, 2026	June 30, 2026	20,000	Aeco 5A	2.71	-	-
Swap	July 01, 2026	September 30, 2026	20,000	Aeco 5A	2.71	-	-
Swap	October 01, 2026	December 31, 2026	6,739	Aeco 5A	2.71	-	-

As at March 31, 2026, we had the following outstanding foreign currency exchange derivative positions:

Period and Type of Instrument	U.S. Dollars Amount Hedged (Thousands of U.S. Dollars)	COP Equivalent of Amount Hedged (Millions of COP)	Reference	Floor Price (COP, Weighted Average)	Cap Price (COP, Weighted Average)
Collars: April 2026, to March 2027	12,000	44,040	COP	3,790	4,080

⁽¹⁾ At March 31, 2026 foreign exchange rate.

Subsequent to March 31, 2026, we entered into the following foreign currency exchange derivative positions:

Period and Type of Instrument	U.S. Dollars Amount Hedged (Thousands of U.S. Dollars)	COP Equivalent of Amount Hedged (Millions of COP)	Reference	Floor Price (COP, Weighted Average)	Cap Price (COP, Weighted Average)
Collars: May 2026, to April 2027	24,000	88,080	COP	3,725	4,004

⁽¹⁾ At March 31, 2026 foreign exchange rate.

Cash Flows

The following table presents our primary sources and uses of cash and cash equivalents and restricted cash and cash equivalents for the periods presented:

(Thousands of U.S. Dollars)	Three Months Ended March 31,	
	2026	2025
Sources of cash and cash equivalents:		
Net loss	\$ (119,172)	\$ (19,280)
Adjustments to reconcile net loss to Adjusted EBITDA ⁽¹⁾ and funds flow from operations ⁽¹⁾		
DD&A expenses	69,874	72,202
Interest expense	49,878	23,235
Severance	2,468	-
Income tax expense	(26,595)	3,553
Non-cash lease expenses	1,468	1,736
Lease payments	(1,687)	(1,567)
Foreign exchange loss	1,425	3,838
Stock-based compensation expense (recovery)	19,676	(517)
Financial instruments loss	77,328	1,910

Other (gain) loss	(728)	52
Adjusted EBITDA ⁽¹⁾	73,935	85,162
Severance	(2,468)	-
Current income tax expense	(5,850)	(8,265)
Contractual interest and other financing expenses	(21,169)	(19,402)
Realized foreign exchange loss	(1,625)	(2,151)
Funds flow from operations ⁽¹⁾	42,823	55,344
Proceeds from exercise of stock options	433	-
Proceeds from disposition of property, plant and equipment	48,598	-
Foreign exchange gain on cash and cash equivalents and restricted cash and cash equivalents	-	38
Net changes in assets and liabilities from operating activities	143,739	19,693
	235,593	75,075
Uses of cash and cash equivalents:		
Additions to property, plant and equipment	(41,540)	(67,504)
Re-purchase of Senior Notes	(8,087)	(1,712)
Senior Notes exchange fees	(12,903)	-
Repayment of debt	(125,000)	(24,828)
Re-purchase of shares of Common Stock	-	(2,415)
Settlement of asset retirement obligations	(925)	(1,807)
Lease payments	(4,417)	(2,253)
Foreign exchange loss on cash, and cash equivalents and restricted cash and cash equivalents	(535)	-
	(193,407)	(100,519)
Net increase (decrease) in cash and cash equivalents and restricted cash and cash equivalents	\$ 42,186	\$ (25,444)

⁽¹⁾ Adjusted EBITDA and funds flow from operations are non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Refer to note 2 “Non-GAAP measures” in “Financial and Operational Highlights” for a definition and reconciliation of this measure.

One of the primary sources of variability in our cash flows from operating activities is the fluctuation in oil prices. Sales volume changes, costs related to operations and debt transactions also impact cash flows. Our cash flows from operating activities are also impacted by foreign currency exchange rate changes. During the three months ended March 31, 2026, funds flow from operations decreased by 23% compared to the corresponding period of 2025, due to higher quality and transportation discounts, higher interest expense partially offset by an increase in Brent price, higher sales volumes, lower operating expenses, and lower current income tax expense.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2025 Annual Report on Form 10-K and have not changed materially since the filing of that document.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity price risk

Our principal market risk relates to oil, natural gas and NGL prices which are volatile and unpredictable and influenced by concerns over world supply and demand imbalance and many other market factors outside of our control. Our revenues are from oil sales at Brent, or Edmonton Light pricing and for gas at AECO pricing and adjusted for quality. As at March 31, 2026, we have entered into commodity price derivative contracts to manage the variability in cash flows associated with the forecasted sale of our oil production, reduce commodity price risk and provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending.

Foreign currency risk

Foreign currency risk is a factor for our Company but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where we operate. Our reporting currency is U.S. dollars and 83% of our revenues are related to the U.S. dollar price of Brent with the remainder related to Canadian dollar price of WTI oil or AECO gas. In Colombia and Ecuador, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures is in U.S. dollars or is based on U.S. dollar prices. The majority of our operating costs, income taxes, VAT, and G&A expenses in all locations are in local currency. In Canada, we receive 100% of our revenue in Canadian dollar and majority of our capital and operating expenditures are in Canadian dollars or are based on Canadian dollar prices.

We have entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs.

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our accounts payable, taxes receivable and payable and deferred tax assets and liabilities in Colombia are denominated in the local currency of the Colombian foreign operations which are our monetary assets. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. We are exposed to interest rate fluctuations on our revolving Canadian credit facility which bears floating rates of interest. As of March 31, 2026, the revolving credit facility remained undrawn.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule 13a-15(b) of the Exchange Act. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that Gran Tierra's disclosure controls and procedures were effective as of March 31, 2026.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended March 31, 2026, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - Other Information

Item 1. Legal Proceedings

See Note 11 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated herein by reference, for any material developments with respect to matters previously reported in our Annual Report on Form 10-K for the year ended December 31, 2025, and any material matters that have arisen since the filing of such report.

Item 1A. Risk Factors

There are numerous factors that affect our business and results of operations, many of which are beyond our control. In addition to information set forth in this Quarterly Report on Form 10-Q, including in Part I, Item 2 “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, you should carefully read and consider the factors set out in Part I, Item 1A “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2025. These risk factors could materially affect our business, financial condition and results of operations. The unprecedented nature of ongoing conflicts in several parts of the world, along with volatility in the worldwide economy and oil and gas industry may make it more difficult to identify all the risks to our business, results of operations and financial condition and the ultimate impact of identified risks.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs ⁽¹⁾
January 1-31, 2026		\$ -	-	2,925,720
February 1-28, 2026			-	2,925,720
March 1-31, 2026		\$ -	-	2,925,720
Total	-	\$ -	-	2,925,720

⁽¹⁾ On November 3, 2025, we implemented a share re-purchase program (the “2025 Program”) through the facilities of the TSX, the NYSE American or alternative programs in Canada or the United States commencing November 6, 2025 and ending on November 5, 2026. Under the 2025 Program, we are able to purchase at prevailing market prices up to 2,925,720 shares of Common Stock, representing approximately 10% of the public float as of October 31, 2025.

Item 5. Other Information

During the three months ended March 31, 2026, no director or Section 16 officer adopted or terminated any Rule 10b5-1 trading arrangements or non-Rule 10b5-1 trading arrangements (in each case, as defined in Item 408(a) of Regulation S-K).

As disclosed in a Form 8-K filed by the Company on March 17, 2026, the Company’s Audit Committee has been conducting an independent investigation into an anonymous complaint.

Consistent with its charter, the Audit Committee takes seriously its responsibility to investigate matters within the scope of its duties. As such, the Audit Committee investigated the allegations in the complaint that it believed were in the scope of its responsibility. The Audit Committee took various steps to ensure that it would meet its fiduciary duties of loyalty, care and oversight in conducting the investigation. Such steps included seeking legal advice from external legal counsel and engaging throughout the entirety of the investigatory process independent legal counsel who conducted investigatory procedures. The engagements concluded under the direction and oversight of the Audit Committee. Following the engagements and multiple meetings and deliberations of the Audit Committee, the Audit Committee concluded that, subject to undertaking certain process improvements, all of which have been satisfactorily implemented by the Company, its investigation is complete.

Item 6. Exhibits

Exhibit No.	Description	Reference
3.1	Certificate of Incorporation.	Incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.2	Certificate of Amendment to Certificate of Incorporation of Gran Tierra Energy Inc., effective May 5, 2023	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed with the SEC on May 5, 2023 (SEC File No. 001-34018).
3.3	Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.4 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.4	Amendment No.1 to Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed with the SEC on August 4, 2021 (SEC File No. 001-34018).
4.1	Indenture related to the 9.750% Senior Secured Amortizing Notes due 2031, dated as of February 18, 2026, among Gran Tierra Energy Inc., the guarantors named therein, and U.S. Bank Trust Company, National Association	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed with the SEC February 20, 2026 (SEC File No. 001-34018).
4.2	First Supplemental Indenture related to the 9.750% Senior Secured Amortizing Notes due 2031, dated as of March 2, 2026, among Gran Tierra Energy Inc., the guarantors named therein, and U.S. Bank Trust Company, National Association.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed with the SEC March 6, 2026 (SEC File No. 001-34018).
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith.

101.INS XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document

101.SCH Inline XBRL Taxonomy Extension Schema Document

101.CAL Inline XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF Inline XBRL Taxonomy Extension Definition Linkbase Document

101.LAB Inline XBRL Taxonomy Extension Label Linkbase Document

101.PRE Inline XBRL Taxonomy Extension Presentation Linkbase Document

104.The cover page from Gran Tierra Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2026, formatted in Inline XBRL (included within the Exhibit 101 attachments).

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GRAN TIERRA ENERGY INC.

Date: May 7, 2026

/s/ Gary S. Guidry

By: Gary S. Guidry
President and Chief Executive Officer
(Principal Executive Officer)

Date: May 7, 2026

/s/ Ryan Ellson

By: Ryan Ellson
Executive Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Gary S. Guidry, certify that:

1. I have reviewed this Form 10-Q of Gran Tierra Energy Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2026

/s/ Gary S. Guidry

By: Gary S. Guidry
President and Chief Executive Officer
(Principal Executive Officer)

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Ryan Ellson, certify that:

1. I have reviewed this Form 10-Q of Gran Tierra Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2026

/s/ Ryan Ellson

By: Ryan Ellson

Executive Vice President and Chief Financial Officer

(Principal Financial and Accounting Officer)

Certification of Chief Executive Officer and Chief Financial Officer

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to the requirement set forth in Rule 13a-14(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") and Section 1350, Chapter 63 of Title 18 of the United States Code (18 U.S.C-§1350), each of Gary S. Guidry, President and Chief Executive Officer of Gran Tierra Energy Inc., a Delaware corporation (the "Company"), and Ryan Ellson, Chief Financial Officer of the Company, does hereby certify, to such officer's knowledge that:

The Quarterly Report on Form 10-Q for the quarter ended March 31, 2026 (the "Form 10-Q") to which this Certification is attached as Exhibit 32.1 fully complies with the requirements of Section 13(a) or 15(d) of the Exchange Act. The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned have set their hands hereto as of the 7th day of May, 2026.

/s/ Gary S. Guidry

By: Gary S. Guidry
President and Chief Executive Officer

/s/ Ryan Ellson

By: Ryan Ellson
Executive Vice President and Chief Financial Officer

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Section 1350, Chapter 63 of Title 18, United States Code) and is not deemed filed with the Securities and Exchange Commission as part of the Form 10-Q or as a separate disclosure document and is not to be incorporated by reference into any filing of the Company under the Securities Act of 1933, as amended, or the Exchange Act (whether made before or after the date of the Form 10-Q), irrespective of any general incorporation language contained in such filing.