

CONSOLIDATED INTERIM FINANCIAL STATEMENTS

Consolidated Balance Sheets (unaudited)

As at (thousands of United States dollars)	NOTE	March 31, 2026	December 31, 2025
ASSETS			
Current assets			
Cash and cash equivalents	21	\$ 44,775	\$ 58,328
Restricted cash and cash equivalents	21	5,504	5,424
Restricted cash	26	75,000	—
Accounts receivable	5	139,864	78,329
Prepays and other current assets		17,809	13,357
Marketable securities	7	57,808	45,090
Derivative financial instruments	23	—	776
Current income tax receivable		65,206	68,363
Crude oil inventory	6	5,459	4,327
		411,425	273,994
Exploration and evaluation	8	206,555	161,125
Property, plant and equipment	9	1,494,144	1,500,213
Long-term inventory	10	168,609	175,426
Other long-term assets	21	15,219	14,629
Deferred tax asset		126,698	142,253
Goodwill		73,452	73,452
		\$ 2,496,102	\$ 2,341,092
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		\$ 237,973	\$ 235,809
Derivative financial instruments	23	29,505	—
Current portion of decommissioning and environmental liabilities	17	8,441	10,158
		275,919	245,967
Bank debt	12	175,200	33,000
Lease obligations	13	7,217	7,814
Cash settled share-based compensation liabilities	19	13,444	15,228
Decommissioning and environmental liabilities	17	81,389	79,007
Other long-term liabilities		7,596	7,143
Deferred tax liability		2,607	—
		563,372	388,159
Shareholders' equity			
Share capital	18	623,505	621,062
Contributed surplus		20,440	20,738
Retained earnings		1,288,785	1,311,133
		1,932,730	1,952,933
		\$ 2,496,102	\$ 2,341,092

Commitments and Contingencies (note 25)

Subsequent Events (note 26)

See accompanying Notes to the Consolidated Interim Financial Statements

Approved by the Board:

"signed"
Sigmund Cornelius
Director

"signed"
Bob MacDougall
Director

Consolidated Statements of Comprehensive Income (unaudited)

(thousands of United States dollars, except per share amounts)	NOTE	For the three months ended March 31,	
		2026	2025
Oil and natural gas sales	14	\$ 271,377	\$ 265,635
Royalties		(36,788)	(36,405)
Net revenue		234,589	229,230
Other revenue	14	1,755	2,512
Commodity risk management contracts (loss)	23	(31,821)	(563)
Revenue		204,523	231,179
Expenses			
Production		57,316	56,858
Transportation		20,257	16,818
Purchased oil		47	192
General and administrative		22,427	17,771
Equity settled share-based compensation expense	18	174	180
Cash settled share-based compensation expense	19	18,493	1,912
Depletion, depreciation and amortization	9	51,289	50,419
Transaction costs	26	610	—
Other expense	15	17,357	1,147
Foreign exchange loss (gain)		2,087	(1,584)
Unrealized gain on marketable securities	7	(12,718)	—
		177,339	143,713
Finance (income)	16	(3,404)	(1,297)
Finance expense	16	6,765	5,056
Net finance expense		3,361	3,759
Income before income taxes		23,823	83,707
Income tax expense			
Current tax expense		1,071	11,887
Deferred tax expense (recovery)		18,163	(8,809)
		19,234	3,078
Net income and comprehensive income for the period		\$ 4,589	\$ 80,629
Basic net income per common share	20	\$ 0.05	\$ 0.82
Diluted net income per common share	20	\$ 0.05	\$ 0.82

See accompanying Notes to the Consolidated Interim Financial Statements

Consolidated Statements of Changes in Equity (unaudited)

For the three months ended March 31,

(thousands of United States dollars)

	2026		2025	
Share capital				
Balance, beginning of period	\$	621,062	\$	632,899
Issuance of common shares under equity-settled plans		2,443		—
Repurchase of shares		—		(2,544)
Balance, end of period	\$	623,505	\$	630,355
Contributed surplus				
Balance, beginning of period	\$	20,738	\$	20,024
Share-based compensation		174		180
Options exercised		(472)		—
Balance, end of period	\$	20,440	\$	20,204
Retained earnings				
Balance, beginning of period	\$	1,311,133	\$	1,178,398
Net income for the period		4,589		80,629
Repurchase of shares		—		(2,695)
Dividends		(26,937)		(26,365)
Balance, end of period	\$	1,288,785	\$	1,229,967
	\$	1,932,730	\$	1,880,526

See accompanying Notes to the Consolidated Interim Financial Statements

Consolidated Statements of Cash Flows (unaudited)

For the three months ended
March 31,

(thousands of United States dollars)	NOTE	2026	2025
Operating activities			
Net income		\$ 4,589	\$ 80,629
Add (deduct) non-cash items			
Depletion, depreciation and amortization	9	51,289	50,419
Non-cash finance expense	16	3,118	3,124
Non-cash other expense	15	299	206
Equity settled share-based compensation expense	18	174	180
Cash settled share-based compensation expense	19	18,493	1,912
Deferred tax expense (recovery)		18,163	(8,809)
Unrealized foreign exchange loss (gain)		710	(4,919)
Unrealized loss (gain) on commodity risk management contracts	23	29,585	(798)
Unrealized gain on marketable securities	7	(12,718)	—
Net change in assets and liabilities	21	(89,616)	(34,323)
Cash provided by operating activities		24,086	87,621
Investing activities			
Property, plant and equipment expenditures	9	(48,282)	(44,951)
Exploration and evaluation expenditures	8	(42,761)	(12,103)
Long-term inventory expenditures, net of transfers and sales	10	6,817	4,648
Corporate acquisition, payment in escrow	26	(75,000)	—
Property acquisition	11	—	(15,968)
Net change in non-cash working capital	21	4,569	5,359
Cash (used in) investing activities		(154,657)	(63,015)
Financing activities			
Dividends	18	(26,937)	(26,365)
Bank debt draw (repayment)	12	142,200	(10,000)
Common shares repurchased	18	—	(5,239)
Issuance of common shares under equity-settled plans	18	1,971	—
Payments on lease obligations	13	(615)	(289)
Net change in non-cash working capital	21	—	103
Cash provided by (used in) financing activities		116,619	(41,790)
Decrease in cash and cash equivalents and restricted cash and cash equivalents for the period		(13,952)	(17,184)
Impact of foreign exchange on foreign currency-denominated cash balances		581	1,554
Cash and cash equivalents and restricted cash and cash equivalents, beginning of period	21	63,943	101,787
Cash and cash equivalents and restricted cash and cash equivalents, end of period	21	\$ 50,572	\$ 86,157

Supplemental Disclosure of Cash Flow Information (note 21)

See accompanying Notes to the Consolidated Interim Financial Statements

Notes to the Consolidated Interim Financial Statements

For the period ended March 31, 2026

(Tabular amounts in thousands of United States dollars, unless otherwise stated. Amounts in text are in United States dollars, unless otherwise stated.)

1. Corporate Information

Parex Resources Inc. and its subsidiaries ("Parex" or "the Company") are in the business of the exploration, development, production and marketing of oil and natural gas in Colombia.

Parex Resources Inc. is a publicly traded company, incorporated and domiciled in Canada. Its registered office is at 2400, 525-8th Avenue S.W., Calgary, Alberta T2P 1G1. The Company was incorporated on August 17, 2009, pursuant to the Business Corporations Act (Alberta).

The condensed interim consolidated financial statements were approved by the Board of Directors on May 11, 2026.

2. Basis of Presentation and Material Accounting Policies

a) Statement of compliance

The condensed interim consolidated financial statements for the three months ended March 31, 2026 has been prepared in accordance with IAS 34, 'Interim financial reporting'. The condensed interim consolidated financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2025, which have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards").

The policies applied in these condensed interim consolidated financial statements are based on IFRS Accounting Standards issued and outstanding as of May 11, 2026, the date the Board of Directors approved the condensed interim consolidated financial statements.

b) Basis of measurement

The condensed interim consolidated financial statements have been prepared under the historical cost convention except for derivative financial instruments and share-based compensation transactions which are measured at fair value. The methods used to measure fair values are discussed in note 4 - Determination of Fair Values.

c) Use of management estimates, judgments and measurement uncertainty

The timely preparation of the condensed interim consolidated financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as at the date of the condensed interim consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the condensed interim consolidated financial statements. Accordingly, actual results could differ from estimated amounts as future confirming events occur.

In preparing these condensed interim consolidated financial statements, the significant judgements made by management in applying the group's accounting policies and the key sources of estimation uncertainty were the same as those applied to the consolidated financial statements for the year ended December 31, 2025.

3. Summary of Material Accounting Policies

The accounting policies adopted are consistent with those of the previous financial year as described in note 3 of the Company's consolidated financial statements for the year ended December 31, 2025 with the addition of the below Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures.

On January 1, 2026, the Company adopted the amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures in the interim period ending March 31, 2026. The amendments for disclosures relates to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. There was not a material effect the Company's condensed interim consolidated financial statements. The Company has applied the election to deem financial liabilities settled in cash using an electronic payment system to be discharged before the settlement date. The amendments have been applied retrospectively with no restatement of comparative information, in accordance with transition requirements on initial application of IFRS 9. There is no adjustment to the opening balance of cash and cash equivalents in the consolidated statements of cash flows.

4. Determination of Fair Values

The methods used in the determination of fair value, for financial and non-financial assets and liabilities have not changed from the previous financial year. Refer to note 4 of the December 31, 2025 consolidated financial statements for details concerning determination of fair values.

5. Accounts Receivable

	March 31, 2026	December 31, 2025
Trade receivables	\$ 130,699	\$ 72,317
Value added taxes (VAT)	9,165	6,012
	\$ 139,864	\$ 78,329

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. VAT receivable is \$9.2 million as at March 31, 2026 (December 31, 2025 - \$6.0 million). All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Crude Oil Inventory

	March 31, 2026	December 31, 2025
Crude oil inventory	\$ 5,459	\$ 4,327

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost using the weighted average cost method and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

7. Marketable Securities

	March 31, 2026	December 31, 2025
Marketable securities	\$ 57,808	\$ 45,090

In 2025, the Company acquired 6,084,986 common shares of GeoPark Ltd (NYSE: GPRK) for aggregate consideration of \$40.5 million (\$6.65 per share). The fair value of these shares at March 31, 2026 was \$57.8 million, resulting in an unrealized gain of \$12.7 million, which is recorded in the consolidated statements of comprehensive income.

8. Exploration and Evaluation Assets

Cost	
Balance at December 31, 2024	\$ 116,928
Additions and transfers from long-term inventory	109,730
Transfers to PP&E	(60,020)
Changes in decommissioning liability	5,627
Exploration and evaluation impairment	(11,140)
Balance at December 31, 2025	\$ 161,125
Additions and transfers from long-term inventory	42,761
Changes in decommissioning liability	2,669
Balance at March 31, 2026	\$ 206,555

Exploration and Evaluation ("E&E") assets consist of the Company's exploration projects which are pending either the determination of proved or probable reserves or impairment. Additions and transfers of \$42.8 million for the three months ended March 31, 2026 represent the Company's share of costs incurred on E&E assets during the period.

For the three months ended March 31, 2026 \$0.7 million of general and administrative costs (three months ended March 31, 2025 - \$0.7 million) have been capitalized in respect of exploration and evaluation activities during the current period.

At March 31, 2026 and December 31, 2025 the Company did not have any E&E assets in Canada.

At March 31, 2026 there were no indicators of impairment noted.

9. Property, Plant and Equipment

	Canada	Colombia	Total
Cost			
Balance at December 31, 2024	\$ 21,432	\$ 3,756,897	\$ 3,778,329
Additions and transfers from long-term inventory	1,340	199,255	200,595
Right-of-use-asset addition (non-cash)	—	4,338	4,338
Transfers from E&E assets	—	60,020	60,020
Additions related to property acquisition - Note 11	—	16,788	16,788
Changes in decommissioning and environmental liability	—	372	372
Balance at December 31, 2025	\$ 22,772	\$ 4,037,670	\$ 4,060,442
Additions and transfers from long-term inventory	191	48,091	48,282
Changes in decommissioning and environmental liability	—	(2,806)	(2,806)
Balance at March 31, 2026	\$ 22,963	\$ 4,082,955	\$ 4,105,918
Accumulated Depreciation, Depletion and Amortization			
Balance at December 31, 2024	\$ 12,513	\$ 2,346,515	\$ 2,359,028
Depletion and depreciation for the year	2,312	196,701	199,013
Depreciation - Right-of-use-asset	740	652	1,392
DD&A included in crude oil inventory costing	—	796	796
Balance at December 31, 2025	\$ 15,565	\$ 2,544,664	\$ 2,560,229
Depletion and depreciation for the period	581	50,067	50,648
Depreciation - Right-of-use-asset	189	452	641
DD&A included in crude oil inventory costing	—	256	256
Balance at March 31, 2026	\$ 16,335	\$ 2,595,439	\$ 2,611,774
Net book value:			
As at December 31, 2024	\$ 8,919	\$ 1,410,382	\$ 1,419,301
As at December 31, 2025	\$ 7,207	\$ 1,493,006	\$ 1,500,213
As at March 31, 2026	\$ 6,628	\$ 1,487,516	\$ 1,494,144

In the three months ended March 31, 2026 property, plant and equipment ("PPE") additions of \$48.3 million mainly relate to drilling and facility costs in Colombia.

For the three months ended March 31, 2026 future development costs of \$320.9 million (three months ended March 31, 2025 - \$411.9 million) were included in the depletion calculation for development and production assets. For the three months ended March 31, 2026 \$1.7 million of general and administrative costs (three months ended March 31, 2025 - \$1.7 million) have been capitalized in respect of development and production activities during the current period.

At March 31, 2026 there were no indicators of impairment noted, or indicators requiring a reversal of previously recorded impairments.

10. Long-term Inventory

The Company has long-lead material inventory such as drill casing, natural gas compressors, and other major equipment.

	Total
Cost	
Balance at December 31, 2024	\$ 199,474
Additions	10,441
Transfers to E&E and PP&E assets	(25,045)
Transfer to production costs	(1,787)
Sale of inventory	(1,187)
Impairment	(6,470)
Balance at December 31, 2025	\$ 175,426
Additions	1,677
Transfers to E&E and PP&E assets	(7,951)
Sale of inventory	(543)
Balance at March 31, 2026	\$ 168,609

For the three months ended March 31, 2026, long-term inventory additions were \$1.7 million, \$8.0 million of long-term inventory was incorporated into the costs of E&E and PP&E projects and \$0.5 million of inventory was sold. At March 31, 2026 there were no indicators of impairment noted.

11. Property Acquisition

On March 14, 2025, Parex, through a foreign subsidiary, acquired an additional 25% working interest in the Azogue field in the LLA-32 Block and 12.5% working interest in the remainder of the LLA-32 Block (the "LLA-32 Acquisition") resulting in 100% working interest in the Block for the Company. The Company paid total net consideration of \$16.0 million.

The consolidated statement of comprehensive income includes results of operation of the LLA-32 Acquisition since the closing date of March 14, 2025. There were no transaction costs associated with the LLA-32 Acquisition.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed

PP&E	\$	16,788
Decommissioning liabilities		(820)
	\$	15,968

Consideration for the acquisition

Purchase price	\$	19,000
Purchase price adjustments		(3,032)
Net consideration	\$	15,968

Cash paid	\$	14,970
Working capital adjustments		998
Total consideration paid	\$	15,968

No working capital was included in the assets acquired.

The pro forma results for the three month period ended March 31, 2025 are shown below, as if the LLA-32 Acquisition had occurred on January 1, 2025. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	\$	269,398
Net revenue less direct costs	\$	158,571

The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. The consolidated statement of comprehensive income for the three months ended March 31, 2025 includes \$3.8 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the three months ended March 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is \$3.0 million. Net income for the three months ended March 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is considered impracticable to calculate.

12. Bank Debt

	March 31, 2026	December 31, 2025
Bank debt	\$ 175,200	\$ 33,000

The Company has a senior secured credit facility with a syndicate of banks which at March 31, 2026 had a borrowing base of \$240.0 million (December 31, 2025 - \$240.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash or letter of credit needs as they arise. At March 31, 2026, \$175.2 million (December 31, 2025 - \$33.0 million) was drawn on the credit facility. The undrawn capacity on the credit facility at March 31, 2026 was \$64.8 million (December 31, 2025 - \$207.0 million).

The credit facility bears interest and fees based in the following manner:

- (i) advances on the revolving facility bear interest at rates per annum equal to U.S. Base Rate or SOFR plus applicable margins;
- (ii) advances on the operating line bear interest at rates per annum equal to Canadian Prime Rate plus applicable margins; and
- (iii) undrawn amounts bear a commitment fee.

The credit facility is secured by the Company's Colombian assets and has final maturity date of May 21, 2027. The next annual review is scheduled to occur in May 2026. The Company expects to amend its existing credit facility as a result of the Frontera Transaction. The Company does not expect a change to the \$240.0 million borrowing base. Key covenants are not expected to change with the amended facility.

Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1, and other standard business operating covenants for each reporting period. The Company was in compliance with all key covenants at March 31, 2026.

The following table lists the Company's key financial covenant at March 31, 2026:

Covenant Description	March 31, 2026
Total Funded Debt to Adjusted EBITDA	Maximum Ratio 3.50:1 0.85

Refer to note 25 – Commitments and Contingencies for details regarding performance guarantees in place with the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petróleos S.A. ("Ecopetrol") in respect of exploration work commitments on the Company's Colombian concessions. These guarantees have been provided in the form of unsecured letters of credit issued by select Latin American banks with varying terms and are reduced from time to time to reflect work performed on the various blocks.

13. Lease Obligations

	Canada	Colombia	Total
Balance at December 31, 2024	\$ 4,071	\$ 1,132	\$ 5,203
Additions	—	4,338	4,338
Interest expense	34	331	365
Lease payments	(586)	(531)	(1,117)
Foreign exchange loss	159	197	356
Balance at December 31, 2025	\$ 3,678	\$ 5,467	\$ 9,145
Interest expense	8	171	179
Lease payments	(181)	(613)	(794)
Foreign exchange loss (gain)	(67)	126	59
Balance at March 31, 2026	\$ 3,438	\$ 5,151	\$ 8,589
Current obligation	(739)	(633)	(1,372)
Long-term obligation	\$ 2,699	\$ 4,518	\$ 7,217

14. Oil and Natural Gas Sales and Other Revenue

The Company's oil and natural gas production sales is determined pursuant to the terms of the revenue agreements. The transaction price for crude oil and natural gas is based on the commodity price in the month of production, adjusted for quality, location, allowable deductions, if any, or other factors. Commodity prices are based on market indices that are determined on a monthly or daily basis.

The Company's oil and natural gas sales by product are as follows:

	For the three months ended March 31,	
	2026	2025
Crude oil	\$ 262,454	\$ 259,877
Natural gas	8,923	5,758
Oil and natural gas sales	\$ 271,377	\$ 265,635

At March 31, 2026, receivables from contracts with customers, which are included in accounts receivable, were \$130.7 million (December 31, 2025 - \$72.3 million).

The Company's other revenue includes pipeline transportation revenue and revenue related to energy generation and use of infrastructure.

	For the three months ended March 31,	
	2026	2025
Other revenue	\$ 1,755	\$ 2,512

15. Other Expense

	For the three months ended March 31,	
	2026	2025
Other Colombian taxes	\$ 1,581	\$ 781
Equity tax	7,000	—
Legal provisions	176	—
(Gain) loss on settlement of decommissioning liabilities	(16)	188
Loss on disposition of tangible assets	139	18
Site restoration costs	6,569	—
Other	1,908	160
Total other expense	\$ 17,357	\$ 1,147

	For the three months ended March 31,	
	2026	2025
Non-cash other expense	\$ 299	\$ 206
Cash other expense	17,058	941
Total other expense	\$ 17,357	\$ 1,147

On February 24, 2026, through Executive Order 0173, the Colombian Government created a new equity tax applicable for fiscal year 2026. The tax applies to legal entities and de facto partnerships that are income tax filers in Colombia. The tax is assessed and becomes payable on equity as of March 1, 2026 equal to or exceeding 200,000 tax unit's value (UVT) (approximately COP\$10.5 billion or US\$2.7 million) at rates from 0.5% to 1.6%. This Executive Order will be challenged through the Constitutional Court and it may or may not be overturned by the Court. The equity tax will be payable in two installments, due in April and June 2026.

Legal provisions have been recognized in respect of estimated fines and penalties mainly arising from environmental regulatory disputes. Management has assessed the likelihood of settlement and determined the best estimate based on relevant legislation and the probability of enforcement outcomes. The timing of the outflows is expected within 10 years. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

A provision has been recognized for the estimated costs required for site restoration in accordance with applicable regulations and contractual obligations. Management expects that a portion of these restoration costs will be recovered through insurance arrangements. Insurance recoveries are recognized only when recovery is virtually certain.

16. Net Finance Expense

	For the three months ended March 31,	
	2026	2025
Bank charges and credit facility fees	\$ 1,218	\$ 789
Interest on bank debt	1,774	769
Accretion on decommissioning and environmental liabilities	2,644	3,222
Interest and other income	(3,404)	(1,297)
Lease obligation interest expense	179	47
Expected credit loss provision (recovery)	474	(99)
Other	476	328
Net finance expense	\$ 3,361	\$ 3,759

	For the three months ended March 31,	
	2026	2025
Non-cash finance expense	\$ 3,118	\$ 3,124
Cash finance expense	243	635
Net finance expense	\$ 3,361	\$ 3,759

17. Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2024	\$ 68,469	\$ 9,206	\$ 77,675
Additions	6,407	3,275	9,682
Property acquisitions - Note 11	702	118	820
Settlements of obligations during the year	(5,877)	(3,635)	(9,512)
Loss (gain) on settlement of obligations	596	(449)	147
Accretion expense	8,160	962	9,122
Change in estimate - inflation and discount rates	(6,197)	(1,192)	(7,389)
Change in estimate - costs and timing of settlements	2,216	1,490	3,706
Foreign exchange loss	3,087	1,827	4,914
Balance, December 31, 2025	\$ 77,563	\$ 11,602	\$ 89,165
Additions	1,769	1,188	2,957
Settlements of obligations during the period	(2,038)	(515)	(2,553)
Gain on settlement of obligations	(16)	—	(16)
Accretion expense	2,338	306	2,644
Change in estimate - inflation and discount rates	1,082	132	1,214
Change in estimate - costs and timing of settlements	(6,977)	2,669	(4,308)
Foreign exchange loss	436	291	727
Balance, March 31, 2026	\$ 74,157	\$ 15,673	\$ 89,830
Current obligation	(6,001)	(2,440)	(8,441)
Long-term obligation	\$ 68,156	\$ 13,233	\$ 81,389

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company's internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at March 31, 2026, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately \$244.0 million as at March 31, 2026 (December 31, 2025 – \$244.5 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.3% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the decommissioning liability is \$6.0 million (December 31, 2025 – \$7.3 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately \$30.0 million as at March 31, 2026 (December 31, 2025 – \$29.7 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.3% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the environmental liability is \$2.4 million (December 31, 2025 – \$2.8 million) that is classified as a current obligation.

18. Share Capital

a) Issued and outstanding common shares

	Number of shares	Amount
Balance, December 31, 2024	98,339,036	\$ 632,899
Repurchase of shares	(2,364,900)	(11,837)
Balance, December 31, 2025	95,974,136	\$ 621,062
Issued for cash - exercise of options	141,294	1,971
Allocation of contributed surplus – exercise of options	—	472
Balance, March 31, 2026	96,115,430	\$ 623,505

The Company has authorized an unlimited number of voting common shares without nominal or par value.

In the three months ended March 31, 2026, there were 141,294 options exercised for proceeds of \$2.0 million (year ended December 31, 2025 - no options were exercised). For the three months ended March 31, 2026, the Company did not repurchase any common shares pursuant to its Normal Course Issuer Bid.

For the year ended December 31, 2025, the Company repurchased 2,364,900 common shares pursuant to its Normal Course Issuer Bid at a cost of \$26.5 million (average cost per share of Cdn\$15.37). The cost to repurchase common shares at a price in excess of their average book value has been charged to retained earnings.

Dividends paid in 2026 were \$26.9 million or Cdn\$0.385 per share (for the year ended December 31, 2025 - \$107.7 million or Cdn\$1.54 per share) to shareholders on record for each dividend payment.

b) Stock options

The Company has a stock option plan which provides for the issuance of options to the Company's officers and certain employees to acquire common shares. The maximum number of options reserved for issuance under the stock option plan may not exceed 5% of the number of common shares issued and outstanding. The stock options vest over a three-year period and expire five years from the date of grant.

	Number of stock options	Weighted average exercise price Cdn\$/option
Balance, December 31, 2024	899,429	22.78
Granted	533,022	12.74
Forfeited	(178,843)	21.52
Balance, December 31, 2025	1,253,608	18.69
Granted	341,386	25.72
Exercised	(141,294)	19.18
Forfeited	(168,583)	20.97
Balance, March 31, 2026	1,285,117	20.20

Stock options outstanding and the weighted average remaining life of the stock options at March 31, 2026 are as follows:

Exercise price Cdn\$	Options outstanding			Options vested		
	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn\$/option	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn\$/option
\$12.74 - \$16.90	455,822	3.93	\$ 12.74	119,539	3.93	\$ 12.74
\$16.91 - \$21.92	211,699	2.93	\$ 21.06	134,540	2.93	\$ 21.06
\$21.93 - \$25.60	129,183	1.85	\$ 22.81	129,183	1.85	\$ 22.81
\$25.61 - \$26.37	341,386	4.95	\$ 25.72	—	—	\$ —
\$26.38 - \$27.02	147,027	0.86	\$ 27.02	147,027	0.86	\$ 27.02
	1,285,117	3.48	\$ 20.20	530,289	2.32	\$ 21.26

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

For the three months ended March 31,	2026	2025
Risk-free interest rate (%)	2.94	2.66
Expected life (years)	4	4
Expected volatility (%)	41	41
Forfeiture rate (%)	3	3
Expected dividend yield (%)	8.35	11.48

The weighted average fair value at the grant date for the three months ended March 31, 2026 was Cdn\$5.76 per option (three months ended March 31, 2025 - Cdn\$1.68 per option). In the three months ended March 31, 2026, there were 141,294 options exercised. The weighted average share price on the exercise date for options exercised in the three months ended March 31, 2026 was \$26.69.

c) Equity settled share-based compensation

	For the three months ended March 31,	
	2026	2025
Option expense	\$ 174	\$ 180
Total equity settled share-based compensation expense	\$ 174	\$ 180

19. Cash Settled Incentive Plans

a) Cash or Share Settled Restricted Share Units and Performance Share Units ("CosRSUs and CosPSUs")

The Company has in place a cash or share settled RSU/PSU incentive plan. This plan provides for the issuance of RSUs and PSUs to certain employees of Parex Canada. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise or the employee can elect to receive the award in Parex common shares. CosRSUs and CosPSUs vest over a three-year period and are exercised at the vest date.

CosRSU:	Number of CosRSUs	Weighted average exercise price Cdn\$/ CosRSU
Balance, December 31, 2024	1,162,252	—
Granted ⁽¹⁾	1,037,144	—
Exercised	(569,595)	—
Forfeited	(133,366)	—
Balance, December 31, 2025	1,496,435	—
Granted ⁽¹⁾	449,619	—
Exercised	(593,585)	—
Forfeited	(104,422)	—
Balance, March 31, 2026	1,248,047	—

(1) Grants include units related to dividend equivalents granted on awards outstanding.

CosPSU:	Number of CosPSUs	Weighted average exercise price Cdn\$/CosPSU
Balance, December 31, 2024	682,587	—
Granted ⁽¹⁾	156,917	—
Granted by performance factor	40,596	—
Exercised	(303,208)	—
Forfeited	(28,793)	—
Balance, December 31, 2025	548,099	—
Granted ⁽¹⁾	65,206	—
Granted by performance factor	235,720	—
Exercised	(532,634)	—
Forfeited	(68,555)	—
Balance, March 31, 2026	247,836	—

(1) Grants include units related to dividend equivalents granted on awards outstanding.

As at March 31, 2026 and 2025, no CosRSUs and CosPSUs were vested.

The weighted average fair value at the grant date for the three months ended March 31, 2026 was Cdn\$26.26 per CosRSU and CosPSU (three months ended March 31, 2025 - Cdn\$12.75 per CosRSU and CosPSU). The weighted average share price on the exercise date for CosRSUs and CosPSUs exercised during the three months ended March 31, 2026 was Cdn\$21.95 (three months ended March 31, 2025 - Cdn\$13.69).

Pursuant to the cash or share settled restricted share unit and performance share unit plan, the Company has granted cash or share settled performance share units to certain employees. The CosPSUs vest three years after the grant date. CosPSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to CosPSUs eligible to vest at the end of the performance period. In March 2026 the board of directors approved a multiplier of 1.67X be applied to the 2023 CosPSU grant resulting in 235,720 CosPSUs issued. In March 2025 the board of directors approved a multiplier of 1.15X be applied to the 2022 CosPSU grant resulting in 40,596 CosPSUs issued.

Obligations for payments of cash under the CosRSUs and CosPSUs plans are accrued as compensation expense over the vesting period based on the fair value of CosRSUs and CosPSUs. The fair value of CosRSUs and CosPSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. As at March 31, 2026, the total CosRSUs and CosPSUs liability accrued is \$8.6 million (December 31, 2025 - \$18.8 million) of which \$2.7 million (December 31, 2025 - \$4.5 million) is classified as long-term in accordance with the three-year vesting period.

b) Long Duration Restricted Share Units and Performance Share Units ("LDRSUs and LDPSUs")

In May 2024, Parex put in place the new long duration RSU/PSU incentive plan. This plan provides for the issuance of LDRSUs and LDPSUs to certain employees of Parex Canada. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise, or the employee can elect to receive the award in common shares. LDRSUs vest over a three-year period and expire 10 years from the date of grant. LDPSUs vest three years after the grant date and expire 10 years from the grant date.

LDRSU:	Number of LDRSUs	Weighted average exercise price Cdn\$/LDRSU
Balance, December 31, 2024	102,495	—
Granted ⁽¹⁾	208,953	—
Balance, December 31, 2025	311,448	—
Granted ⁽¹⁾	98,951	—
Exercised	(14,500)	—
Balance, March 31, 2026	395,899	—

(1) Grants include units related to dividend equivalents granted on awards outstanding.

LDPSU:	Number of LDPSUs	Weighted average exercise price Cdn\$/LDPSU
Balance, December 31, 2024	208,577	—
Granted ⁽¹⁾	414,321	—
Balance, December 31, 2025	622,898	—
Granted ⁽¹⁾	198,319	—
Balance, March 31, 2026	821,217	—

(1) Grants include units related to dividend equivalents granted on awards outstanding.

As at March 31, 2026 129,578 LDRSUs and no LDPSUs were vested. As at March 31, 2025 no LDRSUs and LDPSUs were vested.

The weighted average fair value at the grant date for the three months ended March 31, 2026 was Cdn\$26.32 per LDRSU and LDPSU (three months ended March 31, 2025 - Cdn\$12.75 per LDRSU and LDPSU). The weighted average share price on the exercise date for LDRSUs exercised during the three months ended March 31, 2026 was Cdn\$25.30.

Pursuant to the long duration restricted share unit and performance share unit plan, the Company has granted performance share units to certain employees. The LDPSUs vest three years after the grant date and expire 10 years after the grant date. LDPSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to LDPSUs eligible to vest at the end of the performance period.

Obligations for payments of cash under the LDRSUs and LDPSUs plans are accrued as compensation expense over the vesting period based on the fair value of LDRSUs and LDPSUs. The fair value of LDRSUs and LDPSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. As at March 31, 2026, the total LDRSUs and LDPSUs liability accrued is \$7.8 million (December 31, 2025 - \$4.0 million) of which \$1.9 million (December 31, 2025 - \$2.8 million) is classified as long-term in accordance with the three-year vesting period.

c) *Deferred share units ("DSUs")*

The Company has in place a deferred share unit plan pursuant to which the Company may grant deferred shares to all non-employee directors. The deferred share units vest immediately and are settled in cash upon the retirement of the non-employee director from the Parex Board. The value of the DSUs at the exercise date is equivalent to the five-day weighted average share price at which the common shares of the Company traded for immediately preceding the exercise date. DSUs can only be redeemed following retirement from the Board of Directors of the Company in accordance with the terms of the DSU Plan. The DSUs liability cannot be settled by the issuance of common shares.

	Number of DSU's	Weighted average exercise price Cdn\$/DSU
Balance, December 31, 2024	348,812	—
Granted ⁽¹⁾	128,621	—
Exercised on board retirement	(68,767)	—
Balance, December 31, 2025	408,666	—
Granted ⁽¹⁾	5,266	—
Exercised on board retirement	(54,632)	—
Balance, March 31, 2026	359,300	—

(1) Grants include units related to dividend equivalents granted on awards outstanding.

The weighted average fair value at the grant date for the three months ended March 31, 2026 was \$27.34 per DSU (three months ended March 31, 2025 - Cdn\$13.42 per DSU). The weighted average share price on the exercise date for DSUs exercised during the three months ended March 31, 2026 was Cdn \$20.77. There were no DSUs exercised in the three months ended March 31, 2025.

Given the DSUs vest immediately, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately based on the fair value of the DSU.

As at March 31, 2026, the total DSUs liability accrued is \$7.0 million (December 31, 2025 - \$5.5 million) of which \$6.7 million (December 31, 2025 - \$4.5 million) is classified as long-term in accordance with the terms of the DSU plan.

d) *Cash settled restricted share units ("CRSUs")*

Parex Colombia has a CRSUs plan that provides for the issuance of CRSUs to certain employees of Parex Colombia. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise. CRSUs vest over a three-year period and are exercised at the vest date. The CRSUs liability cannot be settled by the issuance of common shares.

	Number of CRSUs	Weighted average exercise price Cdn\$/CRSU
Balance, December 31, 2024	810,676	—
Granted ⁽¹⁾	1,008,076	—
Exercised	(371,742)	—
Forfeited	(88,248)	—
Balance, December 31, 2025	1,358,762	—
Granted ⁽¹⁾	456,206	—
Exercised	(530,737)	—
Forfeited	(29,297)	—
Balance, March 31, 2026	1,254,934	—

(1) Grants include units related to dividend equivalents granted on awards outstanding.

The weighted average fair value at the grant date for three months ended March 31, 2026 was Cdn\$23.14 per CRSU (three months ended March 31, 2025 - Cdn\$12.73 per CRSU). The weighted average share price on the exercise date for CRSUs exercised for the three months ended March 31, 2026 was Cdn\$21.73 (three months ended March 31, 2025 - Cdn\$13.97).

Obligations for payments of cash under the CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. As at March 31, 2026, the total CRSUs liability accrued is \$7.3 million (December 31, 2025 - \$9.3 million) of which \$2.1 million (December 31, 2025 - \$3.4 million) is classified as long-term in accordance with the three-year vesting period.

e) Cash settled share-based compensation

	For the three months ended March 31,	
	2026	2025
CosRSUs and CosPSUs expense	\$ 7,027	\$ 1,792
LDRSUs and LDPSUs expense	3,735	239
DSUs expense (recovery)	2,377	(179)
CRSUs expense	5,354	60
Total cash settled share-based compensation expense	\$ 18,493	\$ 1,912
Cash payments made upon exercise in the period	\$ 26,152	\$ 10,714

20. Net Income per Share

a) Basic net income per share

	For the three months ended March 31,	
	2026	2025
Net income		
Net income for the purpose of basic net income per share	\$ 4,589	\$ 80,629
Weighted average number of shares for the purposes of basic net income per share (000s)	95,991	98,115
Basic net income per share	\$ 0.05	\$ 0.82

b) Diluted net income per share

	For the three months ended March 31,	
	2026	2025
Net income		
Net income used to calculate diluted net income per share	\$ 4,589	\$ 80,629
Weighted average number of shares for the purposes of basic net income per share (000s)	95,991	98,115
Dilutive effect of stock options on potential common shares	183	—
Weighted average number of shares for the purposes of diluted net income per share (000s)	96,174	98,115
Diluted net income per share	\$ 0.05	\$ 0.82

For the three months ended March 31, 2026, 694,755 stock options (three months ended March 31, 2025 - 1,291,257 stock options) were excluded from the diluted weighted average shares calculation as they were anti-dilutive.

21. Supplemental Disclosure of Cash Flow Information

a) Reconciliation of cash and cash equivalents and restricted cash and cash equivalents

The following table provides a reconciliation of cash and cash equivalents and restricted cash and cash equivalents to the amounts shown in the consolidated statement of cash flows:

	As at March 31,		As at December 31,	
	2026	2025	2025	2024
Cash and cash equivalents	\$ 44,775	\$ 81,025	\$ 58,328	\$ 98,022
Restricted cash and cash equivalents - current	5,504	619	5,424	581
Restricted cash and cash equivalents - long-term ⁽¹⁾	293	4,513	191	3,184
	\$ 50,572	\$ 86,157	\$ 63,943	\$ 101,787

(1) Included in Other long-term assets on the consolidated balance sheet.

b) Net change in assets and liabilities

	For the three months ended March 31,	
	2026	2025
Accounts receivable	\$ (61,535)	\$ (21,900)
Prepays and other current assets	(4,452)	(2,123)
Oil inventory	(1,132)	748
Current income tax receivable/payable	3,157	(6,997)
Accounts payable and accrued liabilities	(18,788)	4,484
Depletion related to oil inventory	256	(219)
Decommissioning and environmental liabilities	(2,553)	(2,854)
Net change in assets and liabilities	\$ (85,047)	\$ (28,861)
Operating	\$ (89,616)	\$ (34,323)
Investing	4,569	5,359
Financing	—	103
Net change in assets and liabilities	\$ (85,047)	\$ (28,861)

c) Interest and taxes paid

	For the three months ended March 31,	
	2026	2025
Cash interest paid	\$ 1,156	\$ 1,057
Cash income taxes paid	\$ —	\$ —

22. Capital Management

The Company's strategy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain the confidence of investors and capital markets.

The Company has a senior secured credit facility with a syndicate of banks which as at March 31, 2026 had a borrowing base in the amount of \$240.0 million (December 31, 2025 - \$240.0 million). The credit facility is intended to serve as a means to increase liquidity and fund cash or letters of credit needs as they arise. As at March 31, 2026, \$175.2 million (December 31, 2025 - \$33.0 million) was drawn on the credit facility.

Refer to note 25 – Commitments and Contingencies for details regarding performance guarantees in place with the ANH and Ecopetrol in respect of exploration work commitments on the Company's Colombian concessions. These guarantees have been provided in the form of unsecured letters of credit issued by select Latin American banks with varying terms and are reduced from time to time to reflect work performed on the various blocks.

As at March 31, 2026, the Company's net working capital surplus was \$135.5 million (December 31, 2025 - \$28.0 million).

The Company has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure, share buy-back and dividend programs to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders' equity, the credit facility and its working capital. As at March 31, 2026 shareholders' equity was \$1,932.7 million (December 31, 2025 - \$1,952.9 million).

23. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash, accounts receivable, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity. The fair value of the revolving credit facility is equal to its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates.

As at March 31, 2026, with other variables unchanged, the impact on the Company's financial instruments of a 10% strengthening (weakening) of the Canadian dollar and COP against the US dollar would have decreased (increased) net income by approximately \$7.1 million.

a) Credit risk

Credit risk is the risk of loss associated with the inability of a third party to fulfill its payment obligations. The Company is exposed to the risk that third parties that owe it money do not meet their obligations. The Company assesses the financial strength of its joint venture partners and oil marketing counterparties in its management of credit exposure.

For the three months ended March 31, 2026 the Company had the majority of its oil sales to two counterparties. The accounts receivable balance as at March 31, 2026 are substantially made up of receivables with customers in the oil and gas industry and are subject to normal industry credit risks. The Company historically has not experienced any collection issues with its crude oil customers. At March 31, 2026, there were no accounts receivable past due (December 31, 2025 - \$nil).

None of the Company's receivables are impaired at March 31, 2026. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

b) Liquidity risk

The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Management typically forecasts cash flows for a period of 12 to 36 months to identify any financing requirements. Liquidity is managed through daily and longer-term cash, debt and equity management strategies. These include estimating future cash generated from operations based on reasonable production and pricing assumptions, estimating future discretionary and non-discretionary capital expenditures and assessing the amount of equity or debt financing available. The Company is committed to maintaining a strong balance sheet and has the ability to change its capital program based on expected operating cash flows. The balance drawn on the Company's \$240.0 million credit facility at March 31, 2026 was \$175.2 million (December 31, 2025 - \$33.0 million).

The following are the contractual maturities of financial liabilities at March 31, 2026:

	Less than 1 year	1-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	\$ 219,337	—	—	7,596	\$ 226,933
Derivative financial instruments	29,505	—	—	—	29,505
Bank debt including interest	—	189,176	—	—	189,176
Lease obligation	1,372	7,217	—	—	8,589
Cash settled share-based compensation payable	17,264	13,444	—	—	30,708
Total	\$ 267,478	209,837	—	7,596	\$ 484,911

The following are the contractual maturities of financial liabilities at December 31, 2025:

	Less than 1 year	1-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	\$ 212,081	—	—	7,143	\$ 219,224
Bank debt including interest	—	36,181	—	—	36,181
Lease obligation	1,331	7,814	—	—	9,145
Cash settled share-based compensation payable	22,397	15,228	—	—	37,625
Total	\$ 235,809	59,223	—	7,143	\$ 302,175

c) Commodity price risk

The Company is exposed to commodity price movements as part of its operations, particularly in relation to the prices received for its oil production. Crude oil is sensitive to numerous worldwide factors, many of which are beyond the Company's control. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Consequently, these changes could also affect the value of the Company's properties, the level of spending for exploration and development and the ability to meet obligations as they come due. The Company's oil production is sold under short-term contracts, exposing it to the risk of near-term price movements.

As at March 31, 2026, the Company had the following crude oil risk management contracts in place:

Period Hedged	Reference	Volume bbls/d	Call Strike Price	Put Strike	Low Put Strike	Premium
April 1, 2026 to April 30, 2026	ICE Brent	12,000	\$70.00	\$60.00	\$53.00	\$—
May 1, 2026 to May 31, 2026	ICE Brent	12,000	\$70.00	\$60.00	\$53.00	\$—
June 1, 2026 to June 30, 2026	ICE Brent	12,000	\$70.00	\$60.00	\$53.00	\$—

These hedging position have been subsequently unwound on April 1, 2026 at a cost of \$29.4 million. The Company is currently unhedged for the remainder of 2026, with full exposure to higher commodity prices.

The table below summarizes the loss on the commodity risk management contracts that were in place during the three months ended March 31, 2026 and 2025:

	For the three months ended March 31,	
	2026	2025
Realized loss on commodity risk management contracts	\$ 2,236	\$ —
Premiums paid on commodity risk management contracts	—	1,361
Unrealized loss (gain) on commodity risk management contracts	29,585	(798)
Total	\$ 31,821	\$ 563

d) Foreign currency risk

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Canadian dollars (Cdn\$) and Colombian pesos (COP\$) while its committed capital expenditures are expected to be primarily denominated in US dollars.

As at March 31, 2026, the Company had the following foreign currency risk management contracts in place:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP	Max Compensation
March 16, 2026 to December 15, 2026	COP	Collar with limited compensation	\$81,000,000	3,700-4,200	800

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three months ended March 31, 2026 and 2025 which is recorded in the financial statement line item "Foreign exchange loss (gain)" in the consolidated statements of comprehensive income:

	For the three months ended March 31,	
	2026	2025
Realized gain on foreign currency risk management contracts	\$ (107)	\$ —
Unrealized gain on foreign currency risk management contracts	(81)	—
Total	\$ (188)	\$ —

24. Segmented Information

The Company has foreign subsidiaries and the following segmented information is provided:

For the three months ended March 31, 2026	Canada		Colombia		Total
Oil and natural gas sales	\$	—	\$	271,377	\$ 271,377
Royalties		—		(36,788)	(36,788)
Net revenue		—		234,589	234,589
Other revenue		—		1,755	1,755
Commodity risk management contracts loss		—		(31,821)	(31,821)
Revenue		—		204,523	204,523
Expenses					
Production		—		57,316	57,316
Transportation		—		20,257	20,257
Purchased oil		—		47	47
General and administrative		11,542		10,885	22,427
Equity settled share-based compensation expense		174		—	174
Cash settled share-based compensation expense		13,139		5,354	18,493
Depletion, depreciation and amortization		770		50,519	51,289
Transaction costs		610		0	610
Other expense		672		16,685	17,357
Foreign exchange loss		1,343		744	2,087
Unrealized gain on marketable securities		(12,718)		0	(12,718)
		15,532		161,807	177,339
Finance (income)		(44)		(3,360)	(3,404)
Finance expense		2,472		4,293	6,765
Net finance expense		2,428		933	3,361
Income (loss) before taxes		(17,960)		41,783	23,823
Current tax expense (recovery)		(5,394)		6,465	1,071
Deferred tax expense		1,054		17,109	18,163
Net income (loss)	\$	(13,620)	\$	18,209	\$ 4,589
Capital assets (end of period)	\$	6,628	\$	1,694,071	\$ 1,700,699
Capital expenditures	\$	191	\$	90,852	\$ 91,043
Total assets (end of period)	\$	208,681	\$	2,287,421	\$ 2,496,102

For the three months ended March 31, 2025	Canada	Colombia	Total
Oil and natural gas sales	\$ —	\$ 265,635	\$ 265,635
Royalties	—	(36,405)	(36,405)
Net revenue	—	229,230	229,230
Other revenue	—	2,512	2,512
Commodity risk management contracts loss	—	(563)	(563)
Revenue	—	231,179	231,179
Expenses			
Production	—	56,858	56,858
Transportation	—	16,818	16,818
Purchased oil	—	192	192
General and administrative	7,690	10,081	17,771
Equity settled share-based compensation expense	180	—	180
Cash settled share-based compensation	1,852	60	1,912
Depletion, depreciation and amortization	801	49,618	50,419
Other expense	—	1,147	1,147
Foreign exchange gain	(17)	(1,567)	(1,584)
	10,506	133,207	143,713
Finance (income)	(130)	(1,167)	(1,297)
Finance expense	1,132	3,924	5,056
Net finance expense	1,002	2,757	3,759
Income (loss) before taxes	(11,508)	95,215	83,707
Current tax expense (recovery)	(1,000)	12,887	11,887
Deferred tax (recovery) expense	1,262	(10,071)	(8,809)
Net income (loss)	\$ (11,770)	\$ 92,399	\$ 80,629
Capital assets (end of period)	\$ 8,213	\$ 1,550,585	\$ 1,558,798
Capital expenditures	\$ 95	\$ 56,959	\$ 57,054
Total assets (end of period)	\$ 49,366	\$ 2,148,589	\$ 2,197,955

For the three months ended March 31, 2026, the Company had two external customers (three months ended March 31, 2025 - two external customers), in the oil and gas industry that subject to normal industry credit risks, constituted more than 10% of commodity sales from production. Sales to these customers totaled \$256.9 million for the three months ended March 31, 2026 and \$253.9 million for the three months ended March 31, 2025.

25. Commitments and Contingencies

a) Colombia

At March 31, 2026, performance guarantees to support the exploration work commitments on the Company's Colombian concessions were in place with the ANH and Ecopetrol joint venture blocks in the amount of \$249.9 million (December 31, 2025 - \$235.1 million). The guarantees have been provided in the form of letters of credit for varying terms that are mainly provided by select Latin American banks on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks.

The value of the Company's exploration commitments as at March 31, 2026 in respect of the Colombia work commitments under E&P contracts, and joint venture farm-in arrangements are estimated to be as follows:

2026	\$	44,119
2027		130,645
2028		94,023
2029		11,689
2030		—
Thereafter		424,107
	\$	704,583

b) Operating leases

In the normal course of business, Parex has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. These commitments include leases for office space and accommodations.

The existing minimum lease payments for office space and accommodations at March 31, 2026 are as follows:

	Total	2026	2027	2028	2029	2030	Thereafter
Office and accommodations	\$ 7,005	2,308	2,624	906	778	389	—

26. Subsequent Events

Frontera Acquisition

On March 10, 2026, the Company entered into an arrangement agreement with Frontera Energy Corporation ("Frontera"), pursuant to which the Company, through a wholly-owned subsidiary, will acquire 100% of the issued and outstanding shares of Frontera Petroleum International Holdings B.V., which holds all of Frontera's exploration and production assets in Colombia, for upfront cash consideration of \$500 million, plus the assumption of debt, in addition to a contingent payment of \$25 million (the "Frontera Transaction"). In connection with the Frontera Transaction, the Company was required to deposit a \$75 million signing payment into a third-party escrow account, which is held by an independent escrow agent in an interest-bearing account and is subject to contractual restrictions governing its release. As the escrowed funds are not available for general corporate purposes and may only be released in accordance with the terms of the arrangement agreement, the escrowed funds are presented as current restricted cash as at March 31, 2026 in the consolidated balance sheets.

If the Frontera Transaction closes, the signing payment amount will be delivered by the escrow agent to Frontera as consideration.

If the arrangement agreement is terminated prior to closing, the signing payment will either be returned to the Company or released to Frontera, depending on the basis for termination. The agreement may be terminated at any time prior to the date on which the arrangement takes effect (the "Effective Date") in certain circumstances, including:

- By mutual written consent of the parties;
- Issuance of a final, non-appealable order permanently prohibiting the transaction;
- Failure of the Effective Time (being 12:01 a.m. (Pacific Standard Time) on the Effective Date) to occur by January 29, 2027, subject to automatic extension to July 29, 2027 under specified conditions;
- Specified breaches by either party; or
- Failure by the Company to fund the closing payment when all closing conditions have been satisfied or waived.

Certain termination rights are not available to a party whose breach was the principal cause of the failure to close.

On April 30, 2026, the Frontera Transaction was approved by the shareholders of Frontera, and on May 4, 2026 the plan of arrangement received court approval under the Business Corporations Act (British Columbia). Accordingly, the signing payment will be released in accordance with the terms of the arrangement agreement and will be delivered by the escrow agent to Frontera as consideration upon closing, which is expected to occur in the second quarter of 2026.

The Company incurred approximately \$0.6 million of transaction costs in the first quarter of 2026 in connection with the Frontera Transaction, which are presented in the consolidated statements of comprehensive income.

Ecopetrol Strategic Partnership

On May 4, 2026, the Company executed an agreement with its strategic partner Ecopetrol whereby the Company expects to earn a 50% participating share in the Casabe and Llanito blocks in the Magdalena Basin of Colombia under a business collaboration agreement with no upfront cost, in exchange for a commitment to invest a gross capital program of \$250 million (\$125 million carry capital) over five years. The agreement is subject to the satisfaction of certain conditions, including regulatory approval.

Senior Notes Offering

As previously announced on May 7, 2026, in conjunction with the Frontera Transaction, Parex completed a \$500 million private placement offering of senior unsecured notes due 2031 (the "Notes") on May 11, 2026 to fund the acquisition and for general corporate purposes. The Notes were priced at par, bear interest at a rate of 8.50% per annum and mature on May 11, 2031.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Parex Resources Inc. ("Parex" or the "Company") for the period ended March 31, 2026 is dated May 11, 2026 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the period ended March 31, 2026, as well as the Company's audited consolidated annual financial statements for the year ended December 31, 2025. The unaudited condensed interim consolidated financial statements and the audited consolidated annual financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"), representing generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada.

Additional information related to Parex is included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated March 3, 2026 ("AIF"), and may be accessed through the SEDAR+ website at www.sedarplus.ca.

All financial amounts are in United States dollars ("USD") unless otherwise stated.

Company Profile

Parex is one of the largest independent oil and gas companies in Colombia, focusing on sustainable, conventional production. The Company's corporate headquarters are in Calgary, Canada, with an operating office in Bogotá, Colombia. Parex's shares trade on the Toronto Stock Exchange under the symbol PXT.

Abbreviations

Refer to the final page of the MD&A for commonly used abbreviations in the document. Refer to the Advisory on Forward-Looking Statements and Non-GAAP and Other Financial Measures Advisory.

References to crude oil or natural gas production in this MD&A refer to the light crude oil and medium crude oil and heavy crude oil and conventional natural gas, respectively, product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*.

Three months ended March 31, 2026 ("first quarter" or "Q1") Highlights

- Crude oil and natural gas production averaged 44,735 boe/d. Average production in 2026 increased 2% compared to the first quarter of 2025 average production of 43,658 boe/d. Refer to "Consolidated Results of Operations" for production split by product type.
- Recognized net income of \$4.6 million (\$0.05 per share basic) compared to net income of \$80.6 million (\$0.82 per share basic) in the first quarter of 2025. The decrease is primarily attributed to unrealized losses on commodity risk management contracts, an increase in deferred tax expense, higher cash settled share-based compensation expense, and the recognition of one-time costs, partially offset by lower current income tax.
- Previously, the Company had hedged Brent crude oil prices for the second quarter ("Q2") of 2026 on approximately 25% of its planned net production. In early Q2 2026, these hedging positions were unwound at a cost of \$29.4 million. The Company is currently unhedged for 2026, with full exposure to higher commodity prices.
- Generated quarterly funds flow provided by operations ("FFO")⁽¹⁾ of \$113.7 million (\$1.18 per share basic⁽²⁾) compared to \$121.9 million (\$1.24 per share basic⁽²⁾) in the first quarter of 2025. The decrease is primarily attributed to the recognition of one-time costs totalling approximately \$17.3 million, partially offset by lower current income tax. One-time costs are comprised of: a Colombian temporary corporate wealth tax of \$7.0 million; site restoration costs of \$6.6 million, with a significant portion expected to be recovered through insurance; and \$3.7 million of project and other general and administrative ("G&A") costs.
- Produced an operating netback⁽²⁾ of \$39.16/boe (Q1 2025 - \$39.40/boe) and an FFO netback⁽²⁾ of \$28.35/boe (Q1 2025 - \$30.90/boe⁽²⁾) from an average Brent price of \$78.38/bbl (Q1 2025 - \$74.98/bbl).
- Incurred \$91.0 million of capital expenditures⁽³⁾ compared to \$57.1 million in the first quarter of 2025. The increase is primarily related to the ramping up of activity at the Orito and Area Sur blocks in the Putumayo, and LLA-32 and LLA-111 in the Llanos, partially offset by lower activity at Cabretero in the Llanos.
- Generated \$22.7 million of free funds flow⁽³⁾ that was used for return of capital with a C\$0.385 per share⁽⁴⁾ regular quarterly dividend paid.
- Bank debt was \$175.2 million, working capital surplus⁽¹⁾ was \$135.5 million and cash was \$44.8 million at quarter end. Bank debt includes borrowings during the quarter of \$142.2 million primarily attributed to a \$75 million deposit related to the Frontera Transaction (as defined below).

(1) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".

(2) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".

(3) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

(4) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Corporate Guidance

For the second half ("H2") of 2026, after accounting for the Frontera Transaction, and the addition of the new producing assets in the Magdalena Basin, the current guidance is:

Category	H2 2026 Guidance (May 12, 2026)
Brent Crude Oil Average Price	\$90/bbl
Average Production ⁽¹⁾	82,000-91,000 boe/d
Funds Flow Provided by Operations Netback ⁽¹⁾⁽²⁾	\$30-33/boe
Funds Flow Provided by Operations ⁽¹⁾⁽³⁾	\$475-525 million
Capital Expenditures ⁽⁴⁾	\$275-295 million
Free Funds Flow ⁽⁴⁾	\$215 million (midpoint)

(1) H2 2026 assumptions: operational downtime: ~5%; Vasconia differential: ~\$4.00/bbl; production expense: \$16.00-20.00/bbl; transportation expense: ~\$7.50/bbl; G&A expense: ~\$5.00/bbl; finance expense: ~\$2.50/bbl, effective tax rate: 12-15%; see "Non-GAAP and Other Financial Measures Advisory".

(2) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".

(3) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".

(4) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

For full-year ("FY") 2026, after accounting for the Frontera Transaction, and the addition of the new producing assets in the Magdalena Basin, average production is expected to be 63,000 to 67,000 boe/d alongside capital expenditures of \$495 to \$515 million⁽¹⁾.

The aforementioned H2 2026 and FY 2026 guidance reflects the ongoing nature of integration efforts and the inherent uncertainty around timing, including the expected close of the strategic transactions and the pace at which synergies may be realized.

Furthermore, the Company anticipates that its outlook for the next few quarters will factor in non-recurring costs, including those related to integration, transition, and financing activities, which could impact FFO.

Refer to "Subsequent Events" for details on the Frontera Transaction and the addition of the new producing assets in the Magdalena Basin.

(1) For the Frontera Transaction, Parex expects to receive the financial benefits from the effective date of January 1, 2026, to the expected close in Q2 2026. Following close, Parex will incorporate the Frontera E&P assets into its financial statements, including the related average production and capital expenditures.

Financial Summary

	For the three months ended March 31,	
(Financial figures in \$'000s except per share amounts)	2026	2025
Light Crude Oil and Medium Crude Oil (bbl/d)	13,980	10,650
Heavy Crude Oil (bbl/d)	29,269	32,207
Average oil production (bbl/d) ⁽¹⁾	43,249	42,857
Average conventional natural gas production (mcf/d) ⁽¹⁾	8,916	4,806
Average oil and natural gas production (boe/d)	44,735	43,658
Production split (% crude oil)	97	98
Oil and natural gas sales price (\$/boe) ⁽⁶⁾	67.67	67.29
Operating netback (\$/boe) ⁽¹⁾	39.16	39.40
Oil and natural gas sales	271,377	265,635
Funds flow provided by operations ⁽⁷⁾	113,702	121,944
Per share – basic ⁽¹⁾⁽³⁾	1.18	1.24
Per share – diluted ⁽¹⁾⁽³⁾	1.18	1.24
Net income	4,589	80,629
Per share – basic ⁽³⁾	0.05	0.82
Per share – diluted ⁽³⁾	0.05	0.82
Dividends paid	26,937	26,365
Per share - Cdn\$ ⁽³⁾⁽⁶⁾	0.385	0.385
Share repurchases	—	5,239
Number of shares repurchased (000s)	—	525
Capital expenditures ⁽²⁾	91,043	57,054
Long-term inventory expenditures, net of transfers and sales	(6,817)	(4,648)
Free funds flow ⁽²⁾	22,659	64,890
EBITDA ⁽²⁾	95,830	139,032
Adjusted EBITDA ⁽²⁾	132,684	135,407
Total assets (end of period)	2,496,102	2,197,955
Working capital surplus (end of period) ⁽⁴⁾⁽⁷⁾	135,506	69,040
Bank debt (end of period) ⁽⁵⁾	175,200	50,000
Weighted average shares outstanding (000s)		
Basic	95,991	98,115
Diluted	96,174	98,115
Outstanding shares (end of period) (000s)	96,115	97,814

(1) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".

(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

(3) Per share amounts (with the exception of dividends) are based on weighted average common shares. Dividends paid per share are based on the number of common shares outstanding at each dividend record date.

(4) Working capital calculation does not take into consideration the undrawn amount available under the syndicated bank credit facility.

(5) Syndicated bank credit facility borrowing base of \$240.0 million as at March 31, 2026 and March 31, 2025.

(6) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

(7) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".

Financial and Operational Results

Consolidated Results of Operations

Parex's oil and gas operations are conducted in Colombia with head office functions conducted in Canada.

	For the three months ended March 31,	
	2026	2025
Average daily production		
Light Crude Oil and Medium Crude Oil (bbl/d)	13,980	10,650
Heavy Crude Oil (bbl/d)	29,269	32,207
Crude Oil (bbl/d)	43,249	42,857
Conventional Natural Gas (mcf/d)	8,916	4,806
Total (boe/d)	44,735	43,658
Production split (% crude oil production)	97	98
Average daily sales of oil and natural gas		
Produced crude oil (bbl/d)	43,075	43,049
Purchased crude oil (bbl/d)	—	13
Produced natural gas (mcf/d)	8,916	4,806
Total (boe/d)	44,561	43,863
Operating netback (\$000s)		
Oil and natural gas sales	\$ 271,377	\$ 265,635
Royalties	(36,788)	(36,405)
Net revenue	234,589	229,230
Production expense	(57,316)	(56,858)
Transportation expense	(20,257)	(16,818)
Purchased oil	(47)	(192)
Operating netback ⁽¹⁾	\$ 156,969	\$ 155,362
Operating netback (per boe)		
Brent (\$/bbl)	\$ 78.38	\$ 74.98
Parex price differential	(10.71)	(7.69)
Oil and natural gas sales ⁽²⁾	67.67	67.29
Royalties ⁽²⁾	(9.17)	(9.22)
Net revenue ⁽²⁾	58.50	58.07
Production expense ⁽²⁾	(14.29)	(14.41)
Transportation expense ⁽²⁾	(5.05)	(4.26)
Operating netback ⁽³⁾	\$ 39.16	\$ 39.40

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".

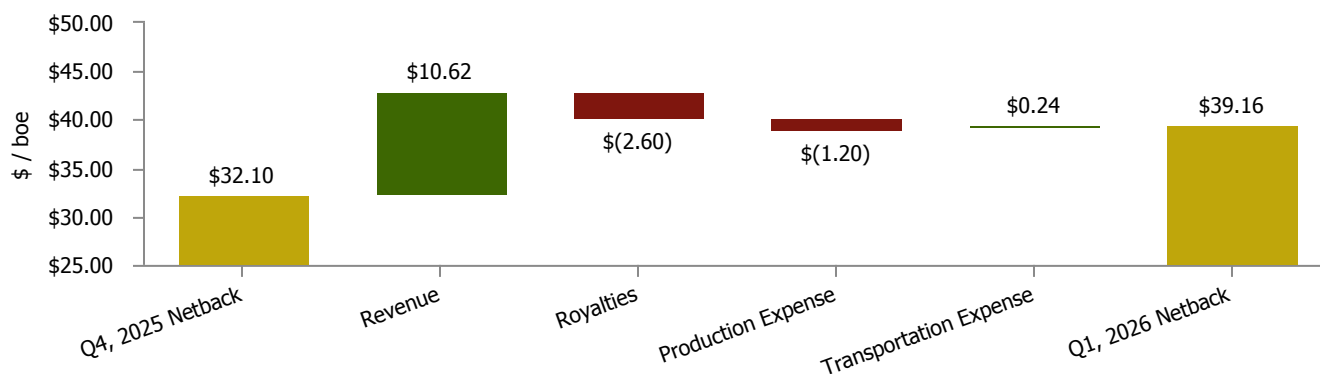
**Change in Operating Netback by Component
Q1/25 vs. Q1/26**



Overall, the Company's benchmark Brent crude oil price increased by \$3.40/bbl, while revenue increased by \$0.38/boe in the first quarter of 2026 as compared to the first quarter of 2025. The decrease in revenue relative to the Brent crude benchmark increase was attributable to increased location and quality differentials. Royalties decreased by \$0.05/boe in the quarter compared to the first quarter of 2025 primarily associated to lower production in areas where high price share royalties are applicable. Production expense in the quarter decreased by \$0.12/boe compared to the first quarter of 2025 due to lower electrical power costs used to power field operations, reduced well workovers and facility maintenance and improved fixed costs absorption due to corporate efficiency initiatives that were implemented, partially offset by the appreciation of the Colombian peso and an increase in variable costs. Transportation expense in the quarter increased by \$0.79/boe compared to the first quarter of 2025 primarily due to an increase in the volume of oil production transported by truck and higher gas volumes transported.

Overall, the operating netback decreased by \$0.24/boe compared to a Brent benchmark crude price increase of \$3.40/bbl.

**Change in Operating Netback by Component
Q4/25 vs. Q1/26**



In the first quarter of 2026, the Company's benchmark Brent oil price increased by \$15.30/bbl, while revenue increased by \$10.62/boe as compared to the fourth quarter of 2025. The decrease in revenue relative to the Brent crude benchmark increase was the result of increased location and quality differentials and wellhead sales discount. Royalties increased by \$2.60/boe primarily associated to the increase in sales price, partially offset by lower production in areas where high price share royalties are applicable. Production expense increased by \$1.20/boe due to higher fuel-powered field operations driven by increased crude oil prices, lower production levels spread over fixed and variable costs, increasing the per-boe cost, and the appreciation of the Colombian peso, partially offset by reduced well workovers and facility maintenance. Transportation expense in the quarter decreased by \$0.24/boe compared to the fourth quarter of 2025 primarily due to a decrease in the volume of oil production transported by truck.

Overall, the operating netback increased by \$7.06/boe compared to a Brent benchmark crude price increase of \$15.30/bbl.

Oil and Natural Gas Sales and Other Revenue

a) Average Daily Production and Sales Volumes (boe/d)

	For the three months ended March 31,	
	2026	2025
Llanos Basin	21,510	18,396
Block LLA-34	19,229	22,210
Magdalena Basin	1,935	2,251
Putumayo Basin	575	—
Total Crude Oil Production	43,249	42,857
Natural gas production	1,486	801
Total Crude oil and natural gas production	44,735	43,658
Crude oil inventory draw (build)	(174)	192
Average daily sales of produced oil and natural gas	44,561	43,850
Purchased oil	—	13
Sales Volumes	44,561	43,863

Crude oil and natural gas production for the first quarter of 2026 averaged 44,735 boe/d.

April 2026 average production was approximately 40,900 boe/d⁽¹⁾. Lower near-term production was primarily driven by LLA-32 from natural declines as well as suboptimal drilling results and subsequent remediation efforts.

The Company expects its standalone average production to grow gradually, exiting Q2 2026 at or greater than 45,000 boe/d. This initial production growth is being driven primarily by the continued scaling of Putumayo operations, and the advancement of recent near-field exploration successes at LLA-111.

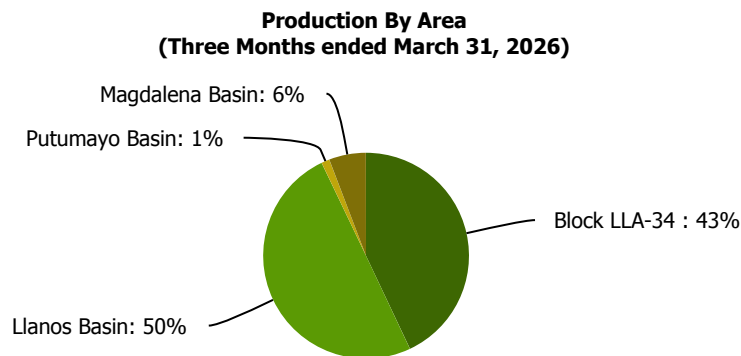
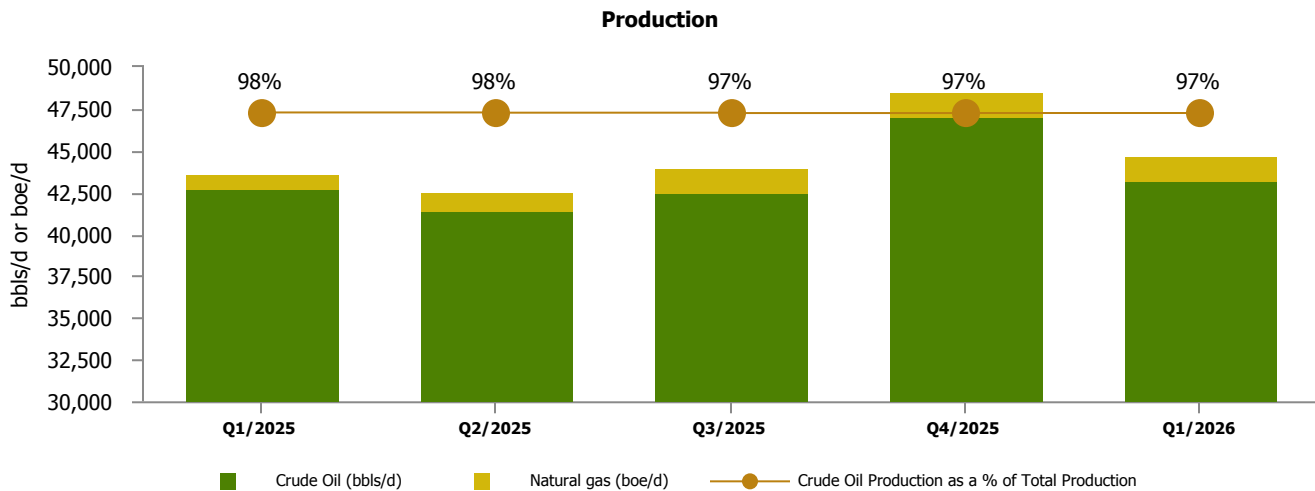
First quarter of 2026 crude oil and natural gas production averaged 44,735 boe/d, an increase of approximately 2% from the first quarter of 2025 production of 43,658 boe/d and a decrease of approximately 8% compared to the fourth quarter of 2025 production of 48,606 boe/d. Refer to "Summary of Quarterly Results" for production split by product type.

The increase in oil and natural gas production in the first quarter of 2026 compared to the first quarter of 2025 is mainly the result of new added production from Block LLA-74 and LLA-32 in the Llanos Basin and an increase in gas production at VIM-1 in the Magdalena Basin. This was partially offset by decreased oil production from Block LLA-34 and the Cabrestero Block in the Southern Llanos Basin, mainly as a result of natural declines and weather-related downtime.

The decrease in crude oil and natural gas production in the first quarter of 2026 compared to the fourth quarter of 2025 was mainly attributed to weather-related downtime and natural declines and drilling results at Block LLA-32.

Oil and natural gas sales in the first quarter of 2026 were 44,561 boe/d compared to 43,863 boe/d for the first quarter of 2025.

(1) Estimated average production for April 1, 2026 to April 30, 2026; light & medium crude oil: ~12,782 bbl/d, heavy crude oil: ~26,760 bbl/d, conventional natural gas: ~8,152 mcf/d; rounded for presentation purposes.



b) Crude Oil Reference and Realized Prices

Average price for the period	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025
Brent (\$/bbl)	78.38	63.08	68.17	66.71	74.98
Parex location (Vasconia) and quality differential (\$/bbl)	(5.52)	(3.03)	(1.94)	(1.87)	(2.26)
Parex wellhead sales discount (\$/bbl)	(5.16)	(3.35)	(3.91)	(3.77)	(5.67)
Parex realized oil sales price (\$/bbl)⁽²⁾	67.70	56.70	62.32	61.07	67.05
Parex realized price (differential) to Brent \$/bbl	(10.68)	(6.38)	(5.85)	(5.64)	(7.93)
Parex transportation expense (\$/bbl) ⁽¹⁾⁽²⁾	(5.10)	(5.47)	(4.88)	(4.58)	(4.34)
Parex price differential and transportation expense (\$/bbl)⁽²⁾	(15.78)	(11.85)	(10.73)	(10.22)	(12.27)

(1) Applies only to direct export cargo sales where Parex incurs the pipeline fees directly. See "Transportation Expense".

(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

During the first quarter of 2026, benchmark Brent oil reference price increased by \$15.30/bbl compared to the fourth quarter of 2025. The increase was primarily driven by the recent geopolitical developments, including the outbreak of war in the Middle East, which resulted in the effective curtailment of a significant portion of global crude oil supply. Crude oil prices were highly volatile in the latter part of the first quarter of 2026 as market participants reassessed expectations regarding the magnitude and duration of the supply disruption.

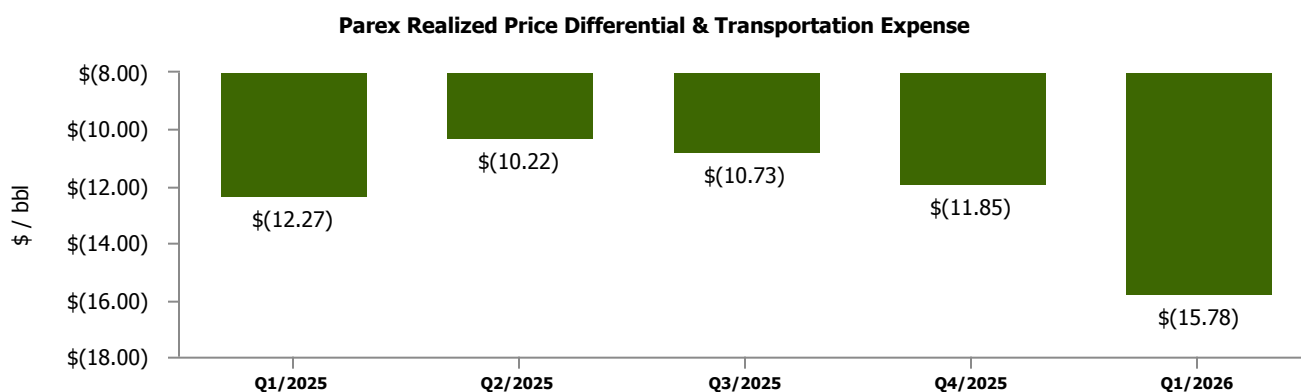
During the first quarter of 2026 the differential between Brent reference pricing and the Company's realized oil sale price was \$10.68/bbl. The differential to Brent crude during the first quarter of 2026 increased by \$4.30/bbl compared to the fourth quarter of 2025 where the differential was \$6.38/bbl. Compared to the first quarter of 2025 Parex's realized oil price differential increased from \$7.93/bbl to \$10.68/bbl, which was primarily driven by an increase in location and quality differentials, having widened significantly following ongoing macroeconomic volatility and expectations around incremental heavy oil supply, partially offset by reduced wellhead sales in favour of direct export sales.

Differences between Parex's realized price and Brent crude price are primarily related to location and quality adjustments, wellhead sale marketing contracts, and the timing of oil sales compared to quarter averages. The location and quality differential between Brent crude pricing also affects Parex's realized sales price and is set in liquid global markets and therefore attributed to factors that are beyond the Company's control making it inherently difficult to forecast.

Parex's realized price differential to Brent crude can fluctuate period over period due to, among other factors, the type of sales contracts and the accounting treatment for oil sold at the wellhead versus direct export sales contracts.

The first quarter 2026 location and quality differential of \$5.52/bbl increased compared to the first quarter of 2025 of \$2.26/bbl, having widened significantly as a result of Venezuelan oil being sold into the US Gulf Coast since the U.S. intervention in Venezuela. This wider differential persisted from early January 2026 into March 2026. Since early March until the date of the MD&A current differentials to Brent are approximately \$1 - \$1 premium to Brent crude prices.

The Vasconia differential to Brent can fluctuate with oil market conditions and for the month of April 2026 was approximately \$0.40/bbl.



c) Natural Gas Sales and Realized Prices

	For the three months ended March 31,	
	2026	2025
Natural gas sales (\$000's)	\$ 8,923	\$ 5,758
Realized sales price (\$/Mcf) ⁽¹⁾	11.12	13.31

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Parex's natural gas sales were \$8.9 million for the three months ended March 31, 2026 compared to \$5.8 million in the comparative period of 2025. The increase in natural gas sales from the comparative period of 2025 is primarily related to increased volumes sold from the Capachos and VIM-1 Blocks, partially offset by a decrease in realized gas sales price.

d) Oil and Natural Gas Sales

First quarter 2026 oil and natural gas sales increased by \$5.7 million or 2% as reconciled in the table below to the first quarter of 2025:

(\$000s)	
Oil and natural gas sales, three months ended March 31, 2025	\$ 265,635
Sales volume of produced oil, an increase of < 1% (26 bopd)	157
Sales volume of purchased oil, a decrease of 100% (13 bopd)	(78)
Oil sales price increase of 1%	2,498
Sales volume and price change of produced natural gas	3,165
Oil and natural gas sales, three months ended March 31, 2026	\$ 271,377

Oil and natural gas sales increased in the three months ended March 31, 2026 compared to the same period in 2025 mainly due to the increase in world oil prices.

e) Crude Oil Inventory in Transit

As at March 31,

(\$000s)	2026		2025	
Crude oil in transit	\$	5,459	\$	1,269

At March 31, 2026, the Company had 132.5 mbbbls of crude oil inventory compared to 31.3 mbbbls at March 31, 2025, which was injected into Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at \$41.20/bbl at March 31, 2026 compared to \$40.54/bbl at March 31, 2025 incurred in bringing the crude oil to its existing condition and location.

A reconciliation of quarter to quarter crude oil inventory movements is provided below:

For the periods ended (mbbls)	Mar. 31, 2026	Dec. 31, 2025	Sep. 30, 2025	Jun. 30, 2025
Crude oil inventory in transit - beginning of the period	116.9	4.9	5.5	31.3
Oil production	3,892.4	4,333.4	3,914.7	3,780.6
Oil sales	(3,876.8)	(4,221.4)	(3,915.3)	(3,806.4)
Crude oil inventory in transit - end of the period	132.5	116.9	4.9	5.5
% of period production	3.4	2.7	0.1	0.1

Crude oil inventory build and (draw) from period to period are subject to factors that the Company does not control such as timing of the number of shipments from storage to export. The Company expects crude oil inventory in future periods to remain in line with normal historic levels of below 5% of period production.

f) Purchased Oil

	For the three months ended March 31,	
	2026	2025
Purchased oil expense (\$000s)	\$ 47	\$ 192

Purchased oil expense has decreased for the three months ended March 31, 2026 compared to the comparative period in 2025 as a result of a decrease in oil blending operations and purchases of partner crude oil. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

g) Other Revenue

The Company's other revenue includes pipeline transportation revenue and revenue related to energy generation and use of infrastructure.

	For the three months ended March 31,	
	2026	2025
Other revenue	\$ 1,755	\$ 2,512

Royalties

	For the three months ended March 31,	
	2026	2025
Base royalties ⁽¹⁾	\$ 21,305	\$ 21,547
Economic rights ⁽²⁾	15,483	14,858
Royalties (\$000s)	\$ 36,788	\$ 36,405
Per unit (\$/boe) ⁽³⁾	9.17	9.22
Percentage of sales ⁽³⁾	14	14

(1) Base royalties are sliding scale royalties based on field production and payable to the Colombian National Hydrocarbon Agency ("ANH"). Refer to the Company's AIF, which may be accessed through the SEDAR+ website at www.sedarplus.ca.

(2) Economic rights include high price share royalties applicable to production in excess of 5 million barrels of oil and X-Factor royalties are an additional royalty applicable to heavy oil production, both payable to ANH. Refer to the Company's AIF, which may be accessed through the SEDAR+ website at www.sedarplus.ca.

(3) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

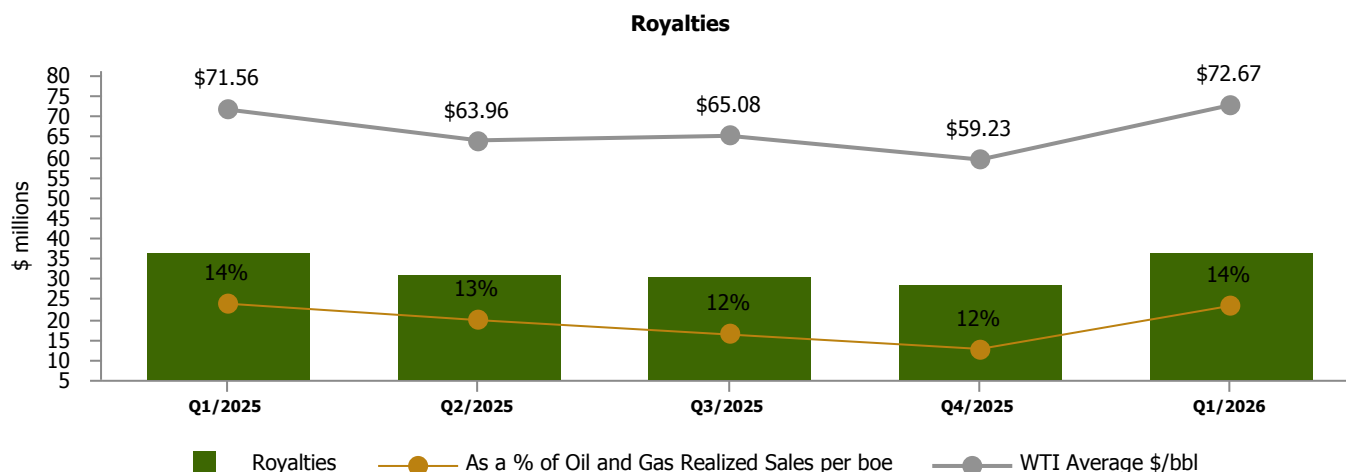
Royalty expense was \$36.8 million in the three months ended March 31, 2026 compared to \$36.4 million for the 2025 comparative period.

Royalties as a percentage of sales were 14% for the three months ended March 31, 2026 compared to 14% for the 2025 comparative period.

The increase in royalty expense was primarily attributable to the increase in world oil prices in 2026, partially offset by lower production in areas where high price share royalties are applicable.

Benchmark WTI prices are used in the high price share royalty ("HPR") calculation. Effectively, higher realized WTI oil prices result in a higher royalty percentage realized. Benchmark WTI prices for the three months ended March 31, 2026 were \$72.67 compared to \$71.56 for the 2025 comparative period and \$59.23 in the fourth quarter of 2025.

For further information concerning the HPR please refer to the Company's AIF, which may be accessed through the SEDAR+ website at www.sedarplus.ca where the calculation is described as a "High Price Share Royalty" in the "Industry Conditions - Colombia - High Price Participation" section.



Production Expense

	For the three months ended March 31,	
	2026	2025
Production expense (\$000s)	\$ 57,316	\$ 56,858
Per unit (\$/boe) ⁽¹⁾	14.29	14.41

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Production expense for the three months ended March 31, 2026 was \$14.29/boe compared to \$14.41/boe for the three months ended March 31, 2025. Production expense for the fourth quarter of 2025 was \$13.09/boe.

The table below provides a reconciliation of the variance in production expense per boe by its main components:

	Q1 2026 vs Q4 2025	Q1 2026 vs Q1 2025
Comparative period production expense per boe ⁽¹⁾	\$ 13.09	\$ 14.41
Power generation	0.95	(0.84)
Well workovers and facility maintenance	(0.64)	(0.85)
Colombian pesos ("COP") appreciation	0.44	1.64
Fixed costs absorption	0.20	(0.46)
Other variable costs	0.25	0.39
Current period production expense per boe⁽¹⁾	\$ 14.29	\$ 14.29

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

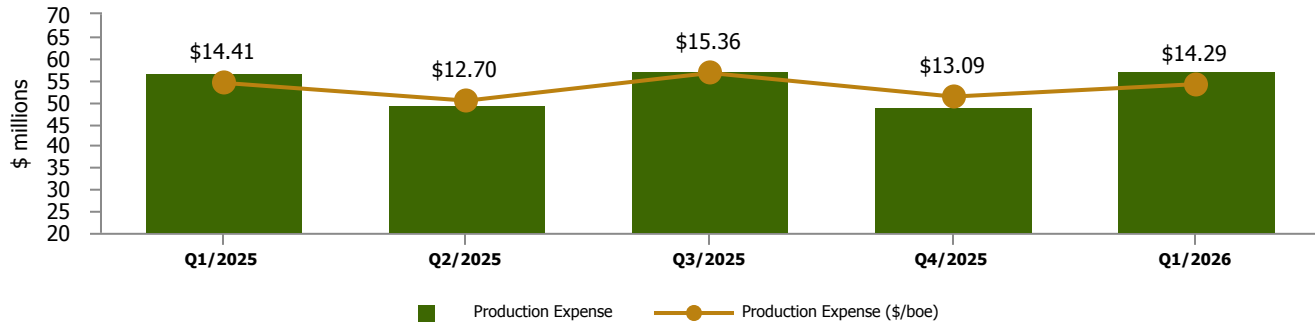
The decrease in production expense per boe for the three months ended March 31, 2026 compared to the three months ended March 31, 2025 is mainly the result of lower electrical power costs used to power field operations, reduced well workovers and facility maintenance and improved fixed costs absorption due to corporate efficiency initiatives that were implemented during 2025. These factors were partially offset by the appreciation of the COP and an increase in variable costs.

The increase in production expense per boe in the first quarter of 2026 compared to the fourth quarter of 2025 is mainly attributable to higher fuel-powered field operations driven by increased crude oil prices, partially offset by lower electrical power costs used in field operations, lower production levels spread over fixed and variable costs, increasing the per-boe cost and the appreciation of the COP. These factors were partially offset by reduced well workovers and facility maintenance.

Field operations in Colombia are substantially electrically powered, although a portion is also fuel powered. Colombia's electricity grid is heavily reliant on hydroelectric power which exposes the Company to fluctuations in power prices due to changes in rainfall and water reservoir levels, as well as electricity supply and demand. Electrical power costs remained elevated in the first quarter of 2025 following drought conditions experienced during 2024. During the first quarter of 2025 power costs began to decrease due to more rainfall in the country, which replenished reservoirs used for hydroelectric power generation, causing power costs to decrease substantially for the remainder of the year. Currently, electrical power costs have declined from the elevated levels seen in late 2024/early 2025 and are more in line with historical norms. Fuel power costs have increased consistent with the increase experienced in world oil prices.

The Company expects its standalone production expense per boe to be approximately \$14-16/boe for the year excluding any impact from the Frontera Transaction and expansion of the Ecopetrol strategic partnership.

Production Expense



Transportation Expense

	For the three months ended March 31,	
	2026	2025
Transportation expense (\$000s)	\$ 20,257	\$ 16,818
Per unit (\$/boe) ⁽¹⁾	5.05	4.26

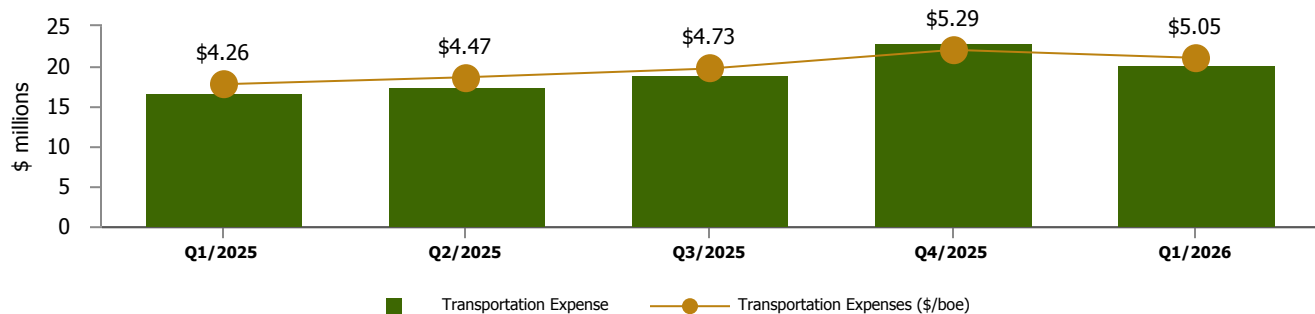
(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility and pipeline tariffs.

For the three months ended March 31, 2026 the cost of transportation on a per boe basis was \$5.05/boe compared to \$4.26/boe for the three months ended March 31, 2025. Transportation expense increased due to an increase in oil volumes transported by truck, higher gas volumes transported from increased gas production at the VIM-1 Block, and the appreciation of the COP. The higher trucked oil volumes are associated with additional production from Azogue on Block LLA-32 and new production from Block LLA-74. Transportation expense will fluctuate period over period due the mix of sales contracts types in force during the period.

The combined transportation expense and price differential from Brent, on a per boe basis, has increased from the first and fourth quarters of 2025. See "Crude Oil Reference and Realized Prices".

Transportation Expense



General and Administrative Expense ("G&A")

(\$000s)	For the three months ended March 31,	
	2026	2025
Gross G&A	\$ 27,229	\$ 21,585
G&A recoveries	(2,419)	(1,335)
Capitalized G&A	(2,383)	(2,479)
Total net G&A	\$ 22,427	\$ 17,771
Per unit (\$/boe) ⁽¹⁾	5.57	4.52

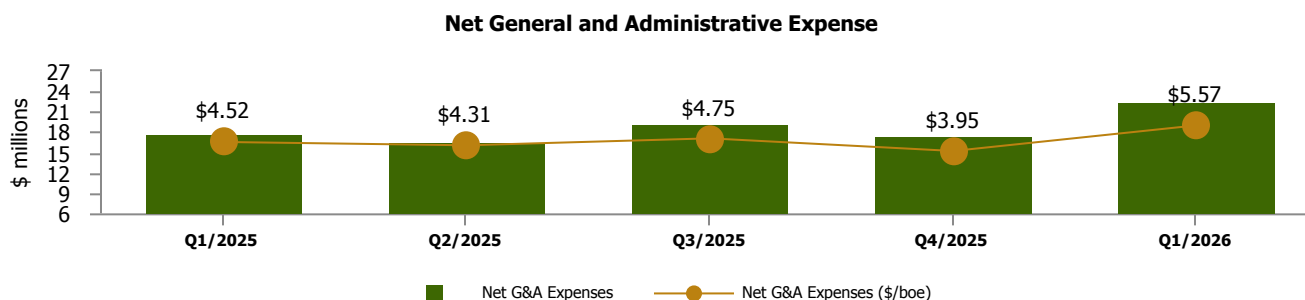
(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Net G&A was \$22.4 million for the three months ended March 31, 2026 compared to \$17.8 million for the three months ended March 31, 2025. Gross G&A was \$27.2 million for the three months ended March 31, 2026 (three months ended March 31, 2025 - \$21.6 million). Gross and net G&A has increased compared to the first quarter of 2025 as a result of one time severance costs of \$2.3 million, increased staffing levels compared to the prior period and the appreciation of the Canadian dollar ("Cdn") and COP.

On a per boe basis, net G&A for three months ended March 31, 2026 increased by 23% to \$5.57 from \$4.52 in the comparative period of 2025 as a result of the increases noted above.

Adjusting for one-time severance costs, normalized net G&A would have been \$20.1 million or \$5.00/boe.

The Company's G&A expense is denominated in local currencies of COP and Cdn which as they appreciate/depreciate have an impact on G&A expense. Refer to the "Foreign Exchange Sensitivity Analysis" for further information.



Share-Based Compensation

(\$000s)	For the three months ended March 31,	
	2026	2025
Equity settled share-based compensation expense	\$ 174	\$ 180
Cash settled share-based compensation expense	18,493	1,912
Total share-based compensation expense	\$ 18,667	\$ 2,092

Share-based compensation expense was \$18.7 million for the three months ended March 31, 2026 compared to \$2.1 million for the three months ended March 31, 2025.

Equity settled share-based compensation expense was \$0.2 million for the three months ended 2026 compared to \$0.2 million for the three months ended March 31, 2025. Equity settled share-based compensation includes the Company's stock option plan.

Cash settled share-based compensation relates to the Company's cash settled incentive plans and includes cash or share settled restricted share units and performance share units ("CosRSUs and "CosPSUs"), long duration restricted share units and performance share units ("LDRSUs" and "LDPSUs"), cash settled restricted share units ("CRSUs") and deferred share units ("DSUs"). Cash settled share-based compensation expense for the three months ended March 31, 2026 was \$18.5 million compared to \$1.9 million for the same period in 2025. The increase in expense for the three months ended March 31, 2026 is mainly attributable to additional units issued and the increase in share price. Parex's share price increased 48% during the first quarter of 2026. The lower expense for the three months ended March 31, 2025 is mainly attributable to the 8% decrease in Parex's share price during the period, partially offset by additional units issued.

Obligations for payments of cash under the Company's cash settled incentive plans are accrued as an expense over the vesting period based on the fair value of the units as described in note 19 - Cash Settled Incentive Plans of the interim consolidated financial statements for the three months ended March 31, 2026. As at March 31, 2026, the total cash settled incentive plans liability accrued was \$30.7 million (December 31, 2025 - \$37.6 million).

Cash payments to settle cash settled share-based compensation in the three months ended March 31, 2026 were \$26.2 million compared to \$10.7 million for the same period in 2025. The increase in the three months ended March 31, 2026 compared to the 2025 comparative period is mainly related to the increase in Parex's share price at the time of settlement and an increase in the number of units settled.

Depletion, Depreciation and Amortization Expense ("DD&A")

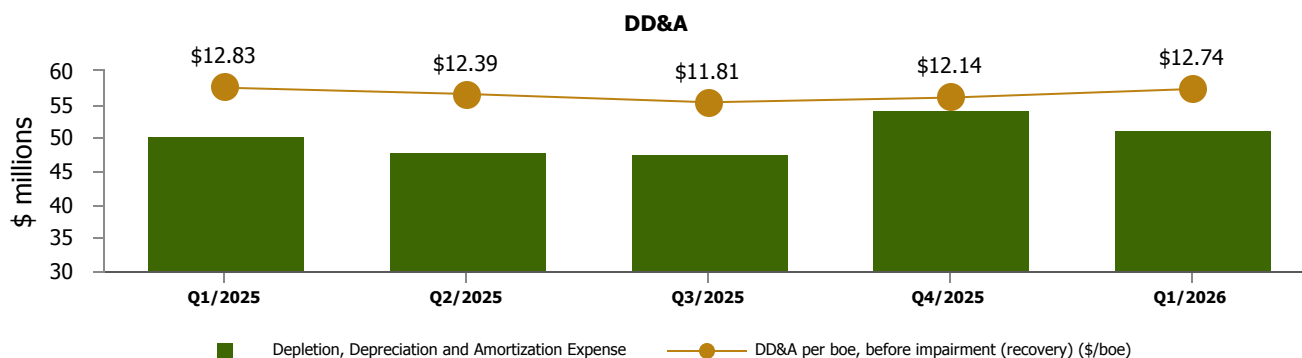
	For the three months ended March 31,	
	2026	2025
DD&A expense (\$000s)	\$ 51,289	\$ 50,419
Per unit (\$/boe) ⁽¹⁾	12.74	12.83

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

First quarter 2026 DD&A was \$51.3 million (\$12.74/boe) compared to \$50.4 million (\$12.83/boe) for the same period in 2025.

For the three months ended March 31, 2026 future development costs of \$320.9 million (three months ended March 31, 2025 - \$411.9 million) were included in the depletion calculation.

First quarter 2026 DD&A of \$12.74/boe has decreased from the comparative period in 2025 of \$12.83/boe and slightly increased from the fourth quarter of 2025 of \$12.14/boe.



Foreign Exchange

(\$000s)	For the three months ended March 31,	
	2026	2025
Foreign exchange loss (gain)	\$ 2,275	\$ (1,584)
Foreign currency risk management contracts gain	(188)	—
Total foreign exchange loss (gain)	\$ 2,087	\$ (1,584)
Average foreign exchange rates		
USD\$/Cdn\$	1.37	1.44
USD\$/COP	3,700	4,193

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Cdn and COP, as the Company's functional currency is the U.S. Dollar ("USD"). The Company has exposure in Colombia and Canada on costs, such as production expense, transportation expense, G&A expense, and income taxes, all of which may be denominated in local currencies. The main drivers of foreign exchange gains and losses recorded on the consolidated statements of comprehensive income are the COP denominated income tax payable and tax withholdings receivable, accounts payable and accounts receivable. The timing of payment settlements, accruals and their adjustments have impacts on foreign exchange gains/losses.

For the three months ended March 31, 2026, a total foreign exchange loss of \$2.1 million was recorded compared to gain of \$1.6 million in the three months ended March 31, 2025.

Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company's consolidated statements of comprehensive income.

The Company reviews its exposure to foreign currency variations on an ongoing basis and maintains cash deposits primarily in USD and COP denominated deposits in Canada, Switzerland and Colombia.

Foreign Exchange Sensitivity Analysis

Cost component	Estimated percent of cost denominated in local currency	\$/boe Impact of change in local currency/\$USD exchange rate	
		10% appreciation of local currency	10% depreciation of local currency
Production expense	90%	\$ 1.29	\$ (1.29)
Transportation expense	50%	\$ 0.25	\$ (0.25)
G&A expense	100%	\$ 0.56	\$ (0.56)

The table above displays the estimated per boe impact of a change in Parex's local currencies and the effect on Parex's key cost components. The component impact in \$/boe terms uses Q1 2026 per boe costs. This analysis ignores all other factors impacting cost structure including, but not limited to, efficiencies, cost reduction strategies, and cost inflation.

As at March 31, 2026, with other variables unchanged, the impact on the Company's financial instruments of a 10% strengthening (weakening) of the Cdn and COP against the USD would have decreased (increased) net income by approximately \$7.1 million.

Other Expense

(\$000s)	For the three months ended March 31,	
	2026	2025
Other Colombian taxes	\$ 1,581	\$ 781
Equity tax	7,000	—
Legal provisions	176	—
(Gain) loss on settlement of decommissioning liabilities	(16)	188
Loss on disposition of tangible assets	139	18
Site restoration costs	6,569	—
Other	1,908	160
Total other expense	\$ 17,357	\$ 1,147

(\$000s)	For the three months ended March 31,	
	2026	2025
Non-cash other expense	\$ 299	\$ 206
Cash other expense	17,058	941
Total other expense	\$ 17,357	\$ 1,147

Other expense is comprised mainly of other Colombian taxes including the 1% surcharge on the sale or export of crude oil effective for 2025 and into 2026, legal provisions, (gain) loss on settlement of decommissioning liabilities, loss on settlement of tangible assets and other items. The non-cash components of other expense include the legal provisions, (gain) loss on settlement of decommissioning liabilities and loss on settlement of tangible assets.

On February 24, 2026, through Executive Order 0173, the Colombian Government created a new equity tax applicable for fiscal year 2026. The tax applies to legal entities and de facto partnerships that are income tax filers in Colombia. The tax is assessed and becomes payable on equity as of March 1, 2026 equal to or exceeding 200,000 tax unit's value (UVT) (approximately COP\$10.5 billion or US\$2.7 million) at rates from 0.5% to 1.6%. This Executive Order will be challenged through the Constitutional Court and it may or may not be overturned by the Court. The equity tax will be payable in two installments, due in April and June 2026.

Legal provisions have been recognized in respect of estimated fines and penalties mainly arising from environmental regulatory disputes. Management has assessed the likelihood of settlement and determined the best estimate based on relevant legislation and the probability of enforcement outcomes. The timing of the outflows is expected within 10 years. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

A provision has been recognized for the estimated costs required for site restoration in accordance with applicable regulations and contractual obligations. Management expects that a portion of these restoration costs will be recovered through insurance arrangements. Insurance recoveries are recognized only when recovery is virtually certain.

Net Finance Expense

(\$000s)	For the three months ended March 31,	
	2026	2025
Bank charges and credit facility fees	\$ 1,218	\$ 789
Interest on bank debt	1,774	769
Accretion on decommissioning and environmental liabilities	2,644	3,222
Interest and other income	(3,404)	(1,297)
Lease obligation interest expense	179	47
Expected credit loss provision (recovery)	474	(99)
Other	476	328
Net finance expense	\$ 3,361	\$ 3,759

(\$000s)	For the three months ended March 31,	
	2026	2025
Non-cash finance expense	\$ 3,118	\$ 3,124
Cash finance expense	243	635
Net finance expense	\$ 3,361	\$ 3,759

Bank charges and credit facility fees relate to bank taxes paid in Colombia and the standby fees related to the Company's credit facility. The non-cash components of net finance expense include the accretion on decommissioning and environmental liabilities and the expected credit loss provision (recovery).

Risk Management

Management of cash flow variability is an integral component of Parex's business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the board of directors ("the Board" or "Board of Directors") to establish risk management guidelines to be used by management. The risk exposure inherent in movements in the price of crude oil, fluctuations in the USD/COP exchange rate and interest rate movements are all proactively reviewed by Parex and as considered appropriate may be managed through the use of derivatives primarily with financial institutions that are members of Parex's syndicated bank credit facility. The Company considers these derivative contracts to be an effective means to manage and forecast cash flow.

Parex has elected not to apply IFRS prescribed "hedge accounting" rules and, accordingly, pursuant to IFRS the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity and foreign exchange forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period-ending commodity and foreign exchange forward strip prices, in respect of any outstanding commodity or foreign exchange derivative contracts.

a) Risk Management Contracts - Brent Crude

As at March 31, 2026, the Company had the following crude oil risk management contracts in place:

Period Hedged	Reference	Volume bbls/d	Call Strike Price	Put Strike	Low Put Strike	Premium
April 1, 2026 to April 30, 2026	ICE Brent	12,000	\$70.00	\$60.00	\$53.00	\$—
May 1, 2026 to May 31, 2026	ICE Brent	12,000	\$70.00	\$60.00	\$53.00	\$—
June 1, 2026 to June 30, 2026	ICE Brent	12,000	\$70.00	\$60.00	\$53.00	\$—

These hedging positions have been subsequently unwound on April 1, 2026 at a cost of \$29.4 million. The Company is currently unhedged for the remainder of 2026, with full exposure to higher commodity prices.

The table below summarizes the loss on the commodity risk management contracts that were in place during the three months ended March 31, 2026 and 2025:

	For the three months ended March 31,	
	2026	2025
Realized loss on commodity risk management contracts	\$ 2,236	\$ —
Premiums paid on commodity risk management contracts	—	1,361
Unrealized loss (gain) on commodity risk management contracts	29,585	(798)
Total	\$ 31,821	\$ 563

b) Risk Management Contracts – Foreign Exchange

The Company is exposed to foreign currency risk as various portions of its cash balances are held in COP and Cdn to fund ongoing costs denominated in those currencies while its committed capital expenditures are primarily denominated in USD.

As at March 31, 2026, the Company had the following foreign currency risk management contracts in place:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP	Max Compensation
March 16, 2026 to December 15, 2026	COP	Collar with limited compensation	\$81,000,000	3,700-4,200	800

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three months ended March 31, 2026 and 2025 which is recorded in the financial statement line item "Foreign exchange loss (gain)" in the consolidated statements of comprehensive income:

	For the three months ended March 31,	
(\$000s)	2026	2025
Realized gain on foreign currency risk management contracts	\$ (107)	\$ —
Unrealized gain on foreign currency risk management contracts	(81)	—
Total	\$ (188)	\$ —

Marketable Securities

	March 31, 2026	December 31, 2025
Marketable securities	\$ 57,808	\$ 45,090

In 2025, the Company acquired 6,084,986 common shares of GeoPark Ltd (NYSE: GPRK) (the "GeoPark Shares") for aggregate consideration of \$40.5 million (\$6.65 per share). The fair value of these shares at March 31, 2026 was \$57.8 million, resulting in an unrealized gain of \$12.7 million, which is recorded in the consolidated statement of comprehensive income.

Parex is exposed to market risk associated with its marketable securities, including the GeoPark Shares, primarily driven by changes in the market price and liquidity of the securities. The market price of the GeoPark Shares may be volatile and could be adversely affected by general market conditions, the investee's performance and disclosures, oil and gas commodity prices, interest and foreign exchange rates, geopolitical developments in the investee's areas of operation, and other factors beyond the Company's control.

Income Tax

(\$000s)	For the three months ended March 31,	
	2026	2025
Current tax expense	\$ 1,071	\$ 11,887
Deferred tax expense (recovery)	18,163	(8,809)
Tax expense	\$ 19,234	\$ 3,078
Effective current tax rate on funds flow provided by operations before tax⁽¹⁾	1 %	9 %

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Current tax expense for the three months ended March 31, 2026 was \$1.1 million compared to \$11.9 million in the three months ended March 31, 2025.

The significant decrease in current tax expense for the three months ended March 31, 2026 compared to the 2025 comparative period is the result of the continued availability of tax pools in Colombia.

Deferred tax expense for the three months ended March 31, 2026 was \$18.2 million compared to a recovery of \$8.8 million in the three months ended March 31, 2025.

The increase in deferred tax expense from the 2025 comparative period is mainly a result of the reversal of temporary differences created between the accounting and tax basis in Colombia. The calculation of current and deferred income tax in Colombia is based on a number of variables which can cause swings in current and deferred income tax. These variables include, but are not limited to, the year-end producing reserves used in calculating depletion for tax purposes, the timing and number of dry hole write-offs permissible for Colombian tax purposes, and currency fluctuations.

2026 Current Tax Guidance

The table below reflects the Company's standalone expected effective current tax rate on funds flow provided by operations before tax in 2026 excluding any impact from the Frontera Transaction and the expansion of Ecopetrol strategic partnership:

Brent price assumption	\$60/bbl	\$70/bbl	\$80/bbl	\$90/bbl	\$100/bbl
Effective current tax rate on before tax funds flow provided by operations ⁽¹⁾	1-3%	5-8%	8-12%	12-15%	15-18%

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Capital Expenditures

For the three months ended March 31, (\$000s)	Colombia		Canada		Total	
	2026	2025	2026	2025	2026	2025
Acquisition of unproved properties	\$ —	\$ 610	\$ —	\$ —	\$ —	\$ 610
Geological and geophysical	—	266	—	—	—	266
Drilling and completion	83,205	53,355	—	—	83,205	53,355
Well equipment and facilities	7,639	2,728	—	—	7,639	2,728
Other	8	—	191	95	199	95
Total capital expenditures⁽¹⁾	\$ 90,852	\$ 56,959	\$ 191	\$ 95	\$ 91,043	\$ 57,054

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Below is additional information related to capital expenditures in the periods by key operating area:

(\$000s)	For the three months ended March 31,	
	2026	2025
Llanos Basin	\$ 45,567	\$ 35,071
Putumayo Basin	31,229	738
Block LLA-34	10,193	12,435
Magdalena Basin	3,855	8,715
Canada and Colombia - Corporate	199	95
Total capital expenditures⁽¹⁾	\$ 91,043	\$ 57,054

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

During the three months ended March 31, 2026 the Company incurred \$91.0 million of capital expenditures with 100% spent on drilling, completion, well equipment and facilities in Colombia. During the three months ended March 31, 2025, the Company incurred \$57.1 million of capital expenditures with 98% spent on drilling, completion, well equipment and facilities in Colombia.

During the three months ended March 31, 2026 the Company's capital expenditures of \$91.0 million were self-funded from funds flow provided by operations of \$113.7 million.

Property Acquisition

On March 14, 2025, Parex, through a foreign subsidiary, acquired an additional 25% working interest in the Azogue field in the LLA-32 Block and 12.5% working interest in the remainder of the LLA-32 Block (the "LLA-32 Acquisition") resulting in 100% working interest in the Block for the Company. The Company paid total net consideration of \$16.0 million.

The consolidated statement of comprehensive income includes results of operation of the LLA-32 Acquisition since the closing date of March 14, 2025. There were no transaction costs associated with the LLA-32 Acquisition.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed

PP&E	\$	16,788
Decommissioning liabilities		(820)
	\$	15,968

Consideration for the acquisition

Purchase price	\$	19,000
Purchase price adjustments		(3,032)
Net consideration	\$	15,968

Cash paid	\$	14,970
Working capital adjustments		998
Total consideration paid	\$	15,968

No working capital was included in the assets acquired.

The pro forma results for the period ended March 31, 2025 are shown below, as if the LLA-32 Acquisition had occurred on January 1, 2025. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	\$	269,398
Net revenue less direct costs or operating netback ⁽¹⁾	\$	158,571

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. The consolidated statement of comprehensive income for the three months ended March 31, 2025 includes \$3.8 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the three months ended March 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is \$3.0 million. Net income for the three months ended March 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is considered impracticable to calculate.

Long-Term Inventory

The Company has long-lead material and equipment inventory such as drill casing, natural gas compressors, and other major equipment. With at times strong demand for material and equipment used in oil and gas operations, periodically the Company secures material and equipment ahead of its upcoming capital programs. The Company plans on deploying this long-lead inventory over the coming years.

Cost	
Balance at December 31, 2024	\$ 199,474
Additions	10,441
Transfers to E&E and PP&E assets	(25,045)
Transfer to production costs	(1,787)
Sale of inventory	(1,187)
Impairment	(6,470)
Balance at December 31, 2025	\$ 175,426
Additions	1,677
Transfers to E&E and PP&E assets	(7,951)
Sale of inventory	(543)
Balance at March 31, 2026	\$ 168,609

The table below represents the other long-term inventory expenditures for the three months ended March 31, 2026 and 2025:

(\$000s)	For the three months ended March 31,	
	2026	2025
Additions	\$ 1,677	\$ 730
Transfers to D&P and E&E assets	(7,951)	(4,434)
Transfer to production costs	—	(944)
Sale of inventory	(543)	—
Total long-term inventory expenditures, net of transfers and sales	\$ (6,817)	\$ (4,648)

Summary of Quarterly Results

Three months ended (\$000s) (except per share amounts)	Mar. 31, 2026	Dec. 31, 2025	Sep. 30, 2025	Jun. 30, 2025
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	13,980	14,835	10,525	10,498
Heavy Crude Oil (bbl/d)	29,269	32,267	32,026	31,047
Crude Oil (bbl/d)	43,249	47,102	42,551	41,545
Conventional Natural Gas (mcf/d)	8,916	9,024	8,412	5,982
Total (boe/d)	44,735	48,606	43,953	42,542
Realized sales price - oil (\$/bbl) ⁽⁶⁾	67.70	56.70	62.32	61.07
Financial (\$000s except per share amounts)				
Oil and natural gas sales	\$ 271,377	\$ 248,713	\$ 252,424	\$ 239,070
Funds flow provided by operations ⁽⁵⁾	\$ 113,702	\$ 122,922	\$ 105,298	\$ 104,821
Per share – basic ⁽²⁾⁽⁴⁾	1.18	1.28	1.09	1.08
Per share – diluted ⁽²⁾⁽⁴⁾	1.18	1.28	1.09	1.08
Net income	\$ 4,589	\$ 74,865	\$ 50,476	\$ 49,113
Per share – basic ⁽⁴⁾	0.05	0.78	0.52	0.50
Per share – diluted ⁽⁴⁾	0.05	0.78	0.52	0.50
Dividends paid	\$ 26,937	\$ 26,853	\$ 26,892	\$ 27,561
Per share - Cdn\$ ⁽⁴⁾⁽⁶⁾	0.385	0.385	0.385	0.385
Capital Expenditures ⁽¹⁾	\$ 91,043	\$ 84,620	\$ 79,961	\$ 88,690
Long-term inventory expenditures, net of transfers and sales	\$ (6,817)	\$ (7,678)	\$ (1,585)	\$ (3,667)
Total assets (end of period)	\$ 2,496,102	\$ 2,341,092	\$ 2,260,531	\$ 2,223,178
Outstanding shares (end of period) (000s)	96,115	95,974	96,564	97,184
Working capital (deficit) surplus (end of period) ⁽³⁾⁽⁵⁾	\$ 135,506	\$ 28,027	\$ (3,167)	\$ 20,048
Three months ended (\$000s) (except per share amounts)				
Mar. 31, 2025				
Dec. 31, 2024				
Sep. 30, 2024				
Jun. 30, 2024				
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,650	9,550	9,064	9,541
Heavy Crude Oil (bbl/d)	32,207	34,882	37,777	43,229
Crude Oil (bbl/d)	42,857	44,432	46,841	52,770
Conventional Natural Gas (mcf/d)	4,806	5,190	4,368	4,788
Total (boe/d)	43,658	45,297	47,569	53,568
Realized sales price - oil (\$/bbl) ⁽⁶⁾	67.05	64.01	69.07	75.69
Financial (\$000s except per share amounts)				
Oil and natural gas sales	\$ 265,635	\$ 277,824	\$ 302,033	\$ 364,874
Funds flow provided by operations ⁽⁵⁾	\$ 121,944	\$ 141,201	\$ 151,773	\$ 180,952
Per share – basic ⁽²⁾⁽⁴⁾	1.24	1.43	1.50	1.77
Per share – diluted ⁽²⁾⁽⁴⁾	1.24	1.43	1.50	1.77
Net income (loss)	\$ 80,629	\$ (69,051)	\$ 65,793	\$ 3,845
Per share – basic ⁽⁴⁾	0.82	(0.70)	0.65	0.04
Per share – diluted ⁽⁴⁾	0.82	(0.70)	0.65	0.04
Dividends paid	\$ 26,365	\$ 26,658	\$ 28,467	\$ 28,528
Per share - Cdn\$ ⁽⁴⁾⁽⁶⁾	0.385	0.385	0.385	0.385
Capital Expenditures ⁽¹⁾	\$ 57,054	\$ 82,110	\$ 82,367	\$ 97,797
Long-term inventory expenditures, net of transfers and sales	\$ (4,648)	\$ (2,569)	\$ (6,318)	\$ 9,817
Total assets (end of period)	\$ 2,197,955	\$ 2,155,062	\$ 2,290,683	\$ 2,324,483
Outstanding shares (end of period) (000s)	97,814	98,339	100,031	101,616
Working capital surplus (end of period) ⁽³⁾⁽⁵⁾	\$ 69,040	\$ 59,397	\$ 37,509	\$ 34,156

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

(2) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".

(3) Working capital does not include the undrawn amount available on the credit facility.

(4) Per share amounts (with the exception of dividends) are based on weighted average common shares. Dividends paid per share are based on the number of common shares outstanding at each dividend record date.

(5) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".

(6) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Factors that Caused Variations Quarter Over Quarter

Trends in net income, oil and natural gas sales and funds flow provided by operations are primarily associated with fluctuations in commodity sales from production which reflect changes in production levels and commodity prices, in addition to fluctuations in foreign currency (see "Foreign Exchange" section). Net income is also impacted by changes in non-cash impairment of property, plant and equipment, exploration and evaluation and long term-inventory assets. Changes in income taxes, as discussed in the section "Income Tax", also impact net income for current and deferred taxes, while funds flow provided by operations is impacted by current income taxes. Working capital trends are primarily associated with fluctuations in funds flow provided by operations, capital and long-term inventory expenditures in accordance with the Company's activities, bank debt borrowing or repayment, timing of settlement of receivables and payables and income taxes and the cost associated with share repurchases and dividend payments.

Refer to "Financial and Operating Results" for detailed discussions on variations during the comparative quarters and to Parex's previously issued annual and interim MD&As for further information regarding changes in prior quarters.

Liquidity and Capital Resources

The Company remains committed to delivering returns to shareholders, while also investing in its assets to provide a total shareholder return. Typically, the Company relies on funds flow provided by operations and its credit facility to meet capital requirements, dividend payments, share repurchases and maintain liquidity. After evaluating its current liquidity, working capital position, projected working capital needs, operational results, and financial forecasts, the Company anticipates that its available cash and cash equivalents, credit facilities, and expected funds flow provided by operations will be sufficient to support the growth of the Company and fund development activities. While the Company deems this outlook reasonable, available cash and cash equivalents are subject to variations and risk associated with ordinary operations, and it cannot guarantee that all or part of its liquidity objective will be met, that sufficient internal funds will be generated, or that external financing will be available if needed.

The Company can adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure, share buy-back and dividend programs to the extent the capital expenditures are not committed. The Company considers its capital structure currently to include shareholders' equity, the credit facility and its working capital. As at March 31, 2026, shareholders' equity was \$1,932.7 million (December 31, 2025 - \$1,952.9 million).

As at March 31, 2026, the Company had working capital surplus of \$135.5 million⁽¹⁾ as compared to working capital surplus of \$28.0 million⁽¹⁾ at December 31, 2025.

As at March 31, 2026, Parex held \$44.8 million of unrestricted cash compared to \$58.3 million at December 31, 2025. The Company's cash balances reside primarily in current accounts with chartered financial institutions, the majority of which are held on account in Canada, Switzerland and Colombia in USD.

Parex's senior secured credit facility is with a syndicate of three Canadian banks and has a current borrowing base of \$240.0 million (December 31, 2025 - \$240.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash or letter of credit needs as they arise. As at March 31, 2026, \$175.2 million (December 31, 2025 - \$33.0 million) was drawn on the credit facility. The credit facility is secured by the Company's Colombian assets and has final maturity date of May 21, 2027. The next annual review is scheduled to occur in May 2026. The Company expects to amend its existing credit facility a result of the Frontera Transaction. The Company does not expect a change to the \$240.0 million borrowing base. Key covenants are not expected to change with the amended facility. Parex expects to draw on the credit facility at various times to manage timing differences associated with timing of vendor payments and oil sales collections. Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1. The Company is in compliance with all covenants.

Refer to note 25 - Commitments and Contingencies of the interim financial statements for the period ended March 31, 2026 for a description of the performance guarantees as well as the unsecured letters of credit.

(1) Capital Management Measure. See "Non-GAAP and Other Financial Measures Advisory".

Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at March 31, 2026 the Company had 96,115,430 common shares outstanding compared to 95,974,136 at December 31, 2025. At May 11, 2026 the Company had 96,180,254 common shares outstanding.

The Company has a stock option plan that provides for the issuance of stock options to acquire common shares to the Company's officers, executives and certain employees resulting in common shares issued from treasury.

As at May 11, 2026 Parex has the following securities outstanding:

	Number	%
Common shares	96,180,254	99 %
Stock options	1,220,293	1 %
	97,400,547	100 %

As of the date of this MD&A, total stock options outstanding represent approximately 1% of the total issued and outstanding common shares.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, Parex has entered into arrangements and incurred obligations that will affect the Company's future operations and liquidity. These commitments primarily relate to joint venture farm-in arrangements, business collaboration agreements and exploration work commitments including seismic and drilling activities. The Company has discretion regarding the timing of capital spending for exploration work commitments, provided that the work is completed by the end of the exploration periods specified in the contracts or the Company can negotiate extensions of the exploration periods. The Company's exploration commitments are described in the Company's AIF under "Principal Properties". These obligations and commitments are considered in assessing cash requirements in the discussion of future liquidity.

At March 31, 2026, performance guarantees to support the exploration work commitments on the Company's Colombian concessions were in place with the ANH and Ecopetrol joint venture blocks in the amount of \$249.9 million (December 31, 2025 - \$235.1 million). The guarantees have been provided in the form of letters of credit for varying terms that are mainly provided by select Latin American banks on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks.

At March 31, 2026, the total lease obligation was \$8.6 million (December 31, 2025 - \$9.1 million) of which \$7.2 million (December 31, 2025 - \$7.8 million) is classified as long-term in accordance with the lease term.

The following table summarizes the Company's estimated undiscounted commitments as at March 31, 2026:

(\$000s)	Total	<1 year	1 – 3 years	3 – 5 years	>5 years
Exploration	\$ 704,583	\$ 44,119	\$ 230,513	\$ 429,951	\$ —
Office and accommodations ⁽¹⁾	7,005	2,556	3,476	973	—
Decommissioning and Environmental Obligations	274,053	8,441	—	—	265,612
Total	\$ 985,641	\$ 55,116	\$ 233,989	\$ 430,924	\$ 265,612

(1) Includes minimum lease payment obligations associated with leases for office space and accommodations.

Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2024	\$ 68,469	\$ 9,206	\$ 77,675
Additions	6,407	3,275	9,682
Property acquisitions - Note 11	702	118	820
Settlements of obligations during the year	(5,877)	(3,635)	(9,512)
Loss (gain) on settlement of obligations	596	(449)	147
Accretion expense	8,160	962	9,122
Change in estimate - inflation and discount rates	(6,197)	(1,192)	(7,389)
Change in estimate - costs and timing of settlements	2,216	1,490	3,706
Foreign exchange loss	3,087	1,827	4,914
Balance, December 31, 2025	\$ 77,563	\$ 11,602	\$ 89,165
Additions	1,769	1,188	2,957
Settlements of obligations during the period	(2,038)	(515)	(2,553)
Gain on settlement of obligations	(16)	—	(16)
Accretion expense	2,338	306	2,644
Change in estimate - inflation and discount rates	1,082	132	1,214
Change in estimate - costs and timing of settlements	(6,977)	2,669	(4,308)
Foreign exchange loss	436	291	727
Balance, March 31, 2026	\$ 74,157	\$ 15,673	\$ 89,830
Current obligation	(6,001)	(2,440)	(8,441)
Long-term obligation	\$ 68,156	\$ 13,233	\$ 81,389

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company's internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at March 31, 2026, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately \$244.0 million as at March 31, 2026 (December 31, 2025 – \$244.5 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.3% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the decommissioning liability is \$6.0 million (December 31, 2025 – \$7.3 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately \$30.0 million as at March 31, 2026 (December 31, 2025 – \$29.7 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.3% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the environmental liability is \$2.4 million (December 31, 2025 – \$2.8 million) that is classified as a current obligation.

Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning expenditures and the impact on the financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. The main factors that can cause expected estimated cash flows in respect of decommissioning liabilities to change are:

- Changes in laws and legislation;
- Construction of new facilities;
- Change in commodity price;
- Change in the estimate of oil reserves and the resulting amendment to the life of reserves;
- Changes in technology; and
- Execution of decommissioning liabilities.

Subsequent Events

Frontera Acquisition

On March 10, 2026, the Company entered into an arrangement agreement with Frontera Energy Corporation ("Frontera"), pursuant to which the Company, through a wholly-owned subsidiary, will acquire 100% of the issued and outstanding shares of Frontera Petroleum International Holdings B.V., which holds all of Frontera's exploration and production assets in Colombia, for upfront cash consideration of \$500 million, plus the assumption of debt, in addition to a contingent payment of \$25 million (the "Frontera Transaction"). In connection with the Frontera Transaction, the Company was required to deposit a \$75 million signing payment into a third-party escrow account, which is held by an independent escrow agent in an interest-bearing account and is subject to contractual restrictions governing its release. As the escrowed funds are not available for general corporate purposes and may only be released in accordance with the terms of the arrangement agreement, the escrowed funds are presented as current restricted cash as at March 31, 2026 in the consolidated balance sheets.

If the Frontera Transaction closes, the signing payment amount will be delivered by the escrow agent to Frontera as consideration.

If the arrangement agreement is terminated prior to closing, the signing payment will either be returned to the Company or released to Frontera, depending on the basis for termination. The agreement may be terminated at any time prior to the date on which the arrangement takes effect (the "Effective Date") in certain circumstances, including:

- By mutual written consent of the parties;
- Issuance of a final, non-appealable order permanently prohibiting the transaction;
- Failure of the Effective Time (being 12:01 a.m. (Pacific Standard Time) on the Effective Date) to occur by January 29, 2027, subject to automatic extension to July 29, 2027 under specified conditions;
- Specified breaches by either party; or
- Failure by the Company to fund the closing payment when all closing conditions have been satisfied or waived.

Certain termination rights are not available to a party whose breach was the principal cause of the failure to close.

On April 30, 2026, the Frontera Transaction was approved by the shareholders of Frontera, and on May 4, 2026 the plan of arrangement received court approval under the Business Corporations Act (British Columbia). Accordingly, the signing payment will be released in accordance with the terms of the arrangement agreement and will be delivered by the escrow agent to Frontera as consideration upon closing, which is expected to occur in the second quarter of 2026.

The Company incurred approximately \$0.6 million of transaction costs in the first quarter of 2026 in connection with the Frontera Transaction, which are presented in the consolidated statements of comprehensive income.

Ecopetrol Strategic Partnership

On May 4, 2026, the Company executed an agreement with its strategic partner Ecopetrol whereby the Company expects to earn a 50% participating share in the Casabe and Llanito blocks in the Magdalena Basin of Colombia under a business collaboration agreement with no upfront cost, in exchange for a commitment to invest a gross capital program of \$250 million (\$125 million carry capital) over five years. The agreement is subject to the satisfaction of certain conditions, including regulatory approval.

Senior Notes Offering

As previously announced on May 7, 2026, in conjunction with the Frontera Transaction, Parex completed a \$500 million private placement offering of senior unsecured notes due 2031 (the "Notes") on May 11, 2026 to fund the acquisition and for general corporate purposes. The Notes were priced at par, bear interest at a rate of 8.50% per annum and mature on May 11, 2031.

Advisory on Forward-Looking Statements

Certain information regarding Parex set forth in this MD&A, including assessments by the Company's management of the Company's plans and future operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "plan", "expect", "continue", "forecast", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are intended to identify forward-looking statements. Such statements represent the Company's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although the Company's management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex. In particular, forward-looking statements contained in this MD&A include, but are not limited to, statements with respect to:

- the Company's operational strategy, plans, priorities and focus;
- Parex's expectation to provide a total shareholder return, while investing in the Company's assets;
- Parex's expectations as to debt levels, commodity risk management and other hedging activities;
- Parex's expectations that a significant portion of its site restoration costs of \$6.6 million this quarter will be recovered through insurance;
- Parex's H2 and FY 2026 guidance, including its anticipated capital expenditures; funds flow provided by operations and average production;
- Parex's expectations regarding its standalone average production growing gradually, exiting Q2 2026 at or greater than 45,000 boe/d, with initial production growth being driven primarily by the continued scaling of Putumayo operations, and the advancement of recent near-field exploration successes at LLA-111;
- Parex's expectation that crude oil inventory in future periods will be in line with normal historic levels;
- Parex's anticipated H2 2026 production expense per boe;
- Parex's expectations that its transportation expense will fluctuate period over period due to the mix of sales contracts types in force during the period;
- that Parex will review its exposure to foreign currency variations on an ongoing basis;
- Parex's foreign exchange sensitivity analysis;
- the terms and purpose of the Company's credit facility including the timing of the next annual review and expectations regarding its amendment in connection with the Frontera Transaction;
- the Company's plan to draw on the credit facility at various times to manage timing differences associated with the timing of vendor payments and oil sales collections;
- the Company's expectation that its available cash and cash equivalents, credit facilities, and expected funds flow provided by operations will be sufficient to support the growth of the Company and fund development activities;
- Parex's estimated undiscounted commitments, including exploration, office and accommodations and decommissioning and environmental obligations, and the anticipated timing thereof;
- the anticipated total undiscounted cash flows required to settle the Company's decommissioning and environmental liability cost, the anticipated timing thereof, and the internal resources available to the Company at the time of settlement;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy and the fluctuation of earnings based on strip prices;
- the anticipated closing of the Frontera Transaction to occur in the second quarter of 2026;
- the Company's expectation to earn a 50% participating share in the Casabe and Llanito blocks under a business collaboration with Ecopetrol;
- the Company's risk management strategy and the use of derivatives primarily with financial institutions to manage movements in the price of crude oil, fluctuations in the USD/COP exchange rate and interest rate movements; that the Company will be able to manage and forecast cash flow through derivative contracts;
- the Company's estimated effective tax rates for 2026;
- Parex's plans of deploying its long-lead material inventory over the coming years;
- anticipated Brent prices and fluctuations in Parex's realized price differential to Brent crude period over period; and
- terms of certain of Parex's contractual obligations.

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to: the impact of general economic conditions in Canada and Colombia; an unpredictable tariff and trade environment; prolonged volatility and fluctuations in commodity prices; industry conditions including changes in laws and regulations such as the adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced in Canada and Colombia; determination by the Organization of Petroleum Exporting Countries and other countries as to production levels; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; imprecisions in reserve, resource and revenue estimates; incorrect forecasts of the production and growth potential of Parex's assets; obtaining required approvals of regulatory authorities in Canada and Colombia; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; fluctuations in foreign exchange or interest rates; geopolitical disruption including the U.S.-Iran conflict and the consequences arising therefrom; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industries; ability to access sufficient capital from internal and external sources; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; risk of failure to achieve the anticipated benefits associated with acquisitions; failure of counterparties to perform under the terms of their contracts; changes to pipeline capacity; the risk that Brent oil prices may be lower than anticipated; the risk that Parex's evaluation of its existing portfolio of development and exploration opportunities may not be consistent with its expectations; the risk that Parex may not have sufficient financial resources in the future to provide distributions to its shareholders; the risk that the Board may not declare dividends in the future and that there may not be base dividend growth or that Parex's dividend policy changes; the risk that Parex's risk management strategy may not be an effective means of managing and forecasting cash flow; the risk that Parex may not be responsive to changes in commodity prices; the risk that the Company's capital and operating expenditures relating to the protection of the environment may be greater than anticipated; the risk that Parex may not meet its production or capital expenditure guidance for the year ended December 31, 2026; the risk that the Company's environmental strategies may not be successful and that the Company may not remain in material compliance with environmental protection legislation; the risk that Parex may not deploy its long-lead inventory when anticipated; the risk that Parex may not be successful in attracting and retaining qualified successors to senior officers in the event of departure; the risks related to the timing and closing of the Frontera Transaction and that Parex may not successfully satisfy the closing conditions related thereto; risks related to the Ecopetrol partnership and the satisfaction of the arrangement's conditions related thereto; the uncertainties and factors discussed under "Decommissioning and Environmental Liabilities" in this MD&A; and other factors, many of which are beyond the control of the Company. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations, business environment and financial results is included in the "Risk Factors" section in the Company's AIF for the year ended December 31, 2025 and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca) or Parex's website at www.parexresources.com.

Although the forward-looking statements contained in this MD&A are based upon assumptions which management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this MD&A, Parex has made assumptions regarding, among other things: current and anticipated commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to areas of the Company's operations and infrastructure; future exchange rates; the price of oil, including the anticipated Brent oil price; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies and environmental legislation on the Company's operations; recoverability of reserves and future production rates; timing and number of dry hole write-offs permitted for Colombian tax purposes; royalty rates; future operating costs; foreign exchange rates; the status of litigation; timing of drilling and completion of wells; receipt of partner, regulatory and community approvals; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; the timing and expected terms of the credit facility amendment; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; that Parex's evaluation of its existing portfolio of development and exploration opportunities is consistent with its expectations; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Company's production and reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; the timing and successful completion of the Frontera Transaction and benefits derived therefrom; the timing and successful completion of the Ecopetrol partnership arrangement and benefits derived therefrom; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; on-stream timing of production from successful exploration wells; operational performance of non-operated producing fields; pipeline capacity; that Parex will have sufficient financial resources to pay dividends and acquire shares pursuant to its NCIB in the future; that strip prices will remain unchanged; and other matters. The ability of the Company to carry out its business plan is primarily dependent upon the continued support of its shareholders, the discovery of economically recoverable reserves and the ability of the Company to obtain financing or generate sufficient cash flow to develop such reserves.

Forward-looking statements and other information contained in this MD&A concerning the oil and natural gas industry in the countries in which it operates and the Company's general expectations concerning this industry are based on estimates prepared by Management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Management has included forward-looking information, and the above summary of assumptions and risks related to forward-looking information in this MD&A in order to provide shareholders with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Parex will derive therefrom. These forward-looking statements are made as of the date of this MD&A and Parex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

This MD&A contains information that may be considered a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to: Parex's H2 an2026 guidance, including its anticipated capital expenditures and funds flow provided by operations; Parex's anticipated H2 2026 production expense per boe; Parex's expectations that its transportation expense will fluctuate period over period due to the mix of sales contracts types in force during the period; Parex's foreign exchange sensitivity analysis; Parex's estimated undiscounted commitments, including exploration, office and accommodations and decommissioning and environmental obligations; and the anticipated timing thereof; the anticipated total undiscounted cash flows required to settle the Company's decommissioning and environmental liability cost, the anticipated timing thereof, and the internal resources available to the Company at the time of settlement; and the Company's estimated effective tax rate for 2026; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will vary from the amounts set forth in this MD&A and such variations may be material. This information has been provided for illustration only and with respect to future periods is based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such financial outlook. The financial outlook contained in this MD&A was made as of the date of this MD&A and was provided for the purpose of providing further information about the Company's potential future business operations. Readers are cautioned that the financial outlook contained in this MD&A is not conclusive and is subject to change.

Distribution Advisory

The Company's future shareholder distributions, including but not limited to the payment of dividends and the acquisition by the Company of its shares pursuant to its NCIB, if any, and the level thereof is uncertain. Any decision to pay further dividends on the common shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith and any special dividends) or acquire shares of the Company will be subject to the discretion of the Board of Directors of Parex and may depend on a variety of factors, including, without limitation the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Company under applicable corporate law. Further, the actual amount, the declaration date, the record date and the payment date of any dividend are subject to the discretion of the Board. There can be no assurance that the Company will pay dividends or repurchase any shares of the Company in the future.

Oil & Gas Matters Advisory

This MD&A contains a number of oil and gas metrics, including operating netbacks and FFO netbacks. These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide security holders with measures to compare the Company's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment or other purposes.

The term "Boe" means a barrel of oil equivalent on the basis of 6 thousand cubic feet ("Mcf") of natural gas to 1 bbl. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1Bbl, utilizing a conversion ratio at 6 Mcf:1 Bbl may be misleading as an indication of value.

Non-GAAP and Other Financial Measures Advisory

This MD&A uses various "non-GAAP financial measures", "non-GAAP ratios", "supplementary financial measures" and "capital management measures" (as such terms are defined in National Instrument 52-112 - Non-GAAP and Other Financial Measures Disclosure), which are described in further detail below. Such measures are not standardized financial measures under IFRS and might not be comparable to similar financial measures disclosed by other issuers. Investors are cautioned that non-GAAP financial measures should not be construed as alternatives to or more meaningful than the most directly comparable GAAP measures as indicators of Parex's performance. The forward-looking non-GAAP financial measures used in this MD&A have no significant difference from their equivalent historical non-GAAP financial measures.

These measures facilitate management's comparisons to the Company's historical operating results in assessing its results and strategic and operational decision-making and may be used by financial analysts and others in the oil and natural gas industry to evaluate the Company's performance. Further, management believes that such financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Company's principal business activities.

Set forth below is a description of the non-GAAP financial measures, non-GAAP ratios, supplementary financial measures and capital management measures used in this MD&A.

Non-GAAP Financial Measures

Capital expenditures, is a non-GAAP financial measure which the Company uses to describe its capital costs associated with oil and gas expenditures. The measure considers both property, plant and equipment expenditures and exploration and evaluation asset expenditures which are items in the Company's statement of cash flows for the period and is calculated as follows:

(\$000s)	For the three months ended March 31,	
	2026	2025
Property, plant and equipment expenditures	\$ 48,282	\$ 44,951
Exploration and evaluation expenditures	42,761	12,103
Capital expenditures	\$ 91,043	\$ 57,054

(\$000s)	For the three months ended					
	December 31, 2025	September 30, 2025	June 30, 2025	December 31, 2024	September 30, 2024	June 30, 2024
Property, plant and equipment expenditures	\$ 47,575	\$ 59,002	\$ 49,067	\$ 62,799	\$ 68,406	\$ 49,214
Exploration and evaluation expenditures	37,045	20,959	39,623	19,311	13,961	48,583
Capital expenditures	\$ 84,620	\$ 79,961	\$ 88,690	\$ 82,110	\$ 82,367	\$ 97,797

Free funds flow, is a non-GAAP financial measure that is determined by funds flow provided by operations less capital expenditures. The Company considers free funds flow to be a key measure as it demonstrates Parex's ability to fund return of capital, such as the normal course issuer bid or dividends, without accessing outside funds and is calculated as follows:

(\$000s)	For the three months ended March 31,	
	2026	2025
Cash provided by operating activities	\$ 24,086	\$ 87,621
Net change in non-cash assets and liabilities	89,616	34,323
Funds flow provided by operations	113,702	121,944
Capital expenditures, excluding corporate acquisitions	91,043	57,054
Free funds flow	\$ 22,659	\$ 64,890

EBITDA, is a non-GAAP financial measure that is defined as net income adjusted for finance income and expense, other expense, income tax expense and depletion, depreciation and amortization.

Adjusted EBITDA, is a non-GAAP financial measure defined as EBITDA adjusted for non-cash impairment charges, share-based compensation expense, transaction costs, unrealized foreign exchange gains (losses) and unrealized gains (losses) on risk management contracts and marketable securities.

The Company considers EBITDA and Adjusted EBITDA to be key measures as they demonstrate Parex's profitability before finance income and expenses, taxes, depletion, depreciation and amortization and other non-cash items. A reconciliation from net income to EBITDA and Adjusted EBITDA is as follows:

(\$000s)	For the three months ended March 31,	
	2026	2025
Net income	\$ 4,589	\$ 80,629
Adjustments to reconcile net income to EBITDA:		
Finance income	(3,404)	(1,297)
Finance expense	6,765	5,056
Other expense	17,357	1,147
Income tax expense	19,234	3,078
Depletion, depreciation and amortization	51,289	50,419
EBITDA	\$ 95,830	\$ 139,032
Share-based compensation expense	18,667	2,092
Transaction costs	610	—
Unrealized foreign exchange loss (gain)	710	(4,919)
Unrealized loss (gain) on commodity risk management contracts	29,585	(798)
Unrealized gain on marketable securities	(12,718)	—
Adjusted EBITDA	\$ 132,684	\$ 135,407

Operating netback, is a non-GAAP financial measure that the Company considers to be a key measure as it demonstrates Parex's profitability relative to current commodity prices. Parex calculates operating netback as oil and natural gas sales from production less royalties, operating, and transportation expense. Refer to "Financial and Operational Results – Consolidated Results of Operations" for the calculation of operating netback.

Non-GAAP Ratios

Operating netback per boe, is a non-GAAP ratio that the Company considers to be a key measure as it demonstrates Parex's profitability relative to current commodity prices. Parex calculates operating netback per boe as operating netback divided by the total equivalent sales volume including purchased oil volumes for oil and natural gas sales price and transportation expense per boe and by the total equivalent sales volume excluding purchased oil volumes for royalties and operating expense per boe.

Funds flow provided by operations netback per boe, is a non-GAAP ratio that includes all cash generated from operating activities and is calculated before changes in non-cash assets and liabilities, divided by produced oil and natural gas sales volumes. The Company considers funds flow provided by operations netback per boe to be a key measure as it demonstrates Parex's profitability after all cash costs relative to current commodity prices.

Basic and diluted funds flow provided by operations per share or FFO per share, is a non-GAAP ratio that is calculated by dividing funds flow provided by operations by the weighted average number of basic and diluted shares outstanding. Parex presents basic and diluted funds flow provided by operations per share whereby per share amounts are calculated using weighted-average shares outstanding, consistent with the calculation of earnings per share. The Company considers basic and diluted funds flow provided by operations per share or FFO per share to be a key measure as it demonstrates Parex's profitability after all cash costs relative to the weighted average number of basic and diluted shares outstanding.

Capital Management Measures

Funds flow provided by operations, is a capital management measure that includes all cash generated from operating activities and is calculated before changes in non-cash assets and liabilities. The Company considers funds flow provided by operations to be a key measure as it demonstrates Parex's profitability after all cash costs. A reconciliation from cash provided by operating activities to funds flow provided by operations is as follows:

(\$000s)	For the three months ended March 31,	
	2026	2025
Cash provided by operating activities	\$ 24,086	\$ 87,621
Net change in non-cash assets and liabilities	89,616	34,323
Funds flow provided by operations	\$ 113,702	\$ 121,944

(\$000s)	For the three months ended					
	December 31, 2025	September 30, 2025	June 30, 2025	December 31, 2024	September 30, 2024	June 30, 2024
Cash provided by operating activities	\$ 107,744	\$ 86,992	\$ 142,642	\$ 67,847	\$ 181,874	\$ 222,782
Net change in non-cash assets and liabilities	15,178	18,306	(37,821)	73,354	(30,101)	(41,830)
Funds flow provided by operations	\$ 122,922	\$ 105,298	\$ 104,821	\$ 141,201	\$ 151,773	\$ 180,952

Working capital surplus (deficit), is a capital management measure which the Company uses to describe its liquidity position and ability to meet its short-term liabilities. Working capital surplus (deficit) is defined as current assets less current liabilities:

(\$000s)	For the three months ended March 31,	
	2026	2025
Current assets	\$ 411,425	\$ 259,256
Current liabilities	275,919	190,216
Working capital surplus	\$ 135,506	\$ 69,040

(\$000s)	For the three months ended					
	December 31, 2025	September 30, 2025	June 30, 2025	December 31, 2024	September 30, 2024	June 30, 2024
Current assets	\$ 273,994	\$ 224,109	\$ 239,485	\$ 245,943	\$ 248,208	\$ 281,846
Current liabilities	245,967	227,276	219,437	186,546	210,699	247,690
Working capital surplus (deficit)	\$ 28,027	\$ (3,167)	\$ 20,048	\$ 59,397	\$ 37,509	\$ 34,156

Supplementary Financial Measures

"**DD&A expense per boe**" is comprised of DD&A expense, as determined in accordance with IFRS, divided by the total production.

"**Dividends paid per share**" is comprised of dividends declared, as determined in accordance with IFRS, divided by the number of shares outstanding at the dividend record date.

"**Effective current tax rate as a per cent of funds flow provided by operations before tax**" is comprised of current income tax expense, as determined in accordance with IFRS, divided by funds flow provided by operations before tax.

"**G&A expense per boe**" is comprised of net G&A expense after recoveries and capitalization, as determined in accordance with IFRS, divided by the total production.

"**Net revenue per boe**" is comprised of net revenue, as determined in accordance with IFRS, divided by the total equivalent sales volume and includes purchased oil volumes.

"**Oil and natural gas sales price per boe**" is comprised of total commodity sales from oil and natural gas production, as determined in accordance with IFRS, divided by the total oil and natural gas sales volumes including purchased oil volumes.

"**Price differential and transportation expense per bbl**" is comprised of realized oil sales price per bbl, as defined herein, less Brent crude price to calculate the price differential, plus transportation expense per bbl as defined herein.

"**Production expense per boe**" is comprised of production expense, as determined in accordance with IFRS, divided by the total equivalent sales volume and excludes purchased oil volumes.

"**Realized oil sales price per bbl**" is comprised of total oil sales, as determined in accordance with IFRS, divided by the total oil sales volumes equivalent sales volume including purchased oil volumes.

"**Realized natural gas price per Mcf**" is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the natural gas sales volumes.

"**Royalties per boe**" is comprised of royalties, as determined in accordance with IFRS, divided by the total equivalent sales volume and excludes purchased oil volumes.

"**Royalties as a percentage of sales**" is comprised of royalties, as determined in accordance with IFRS, divided by the total equivalent sales from production, excluding purchased oil volumes, as determined in accordance with IFRS.

"**Transportation expense per bbl**" is comprised of transportation expense, as determined in accordance with IFRS, divided by the total oil sales volumes equivalent sales volume including purchased oil volumes.

"**Transportation expense per boe**" is comprised of transportation expense, as determined in accordance with IFRS, divided by the total equivalent sales volumes including purchased oil volumes.

Business Environment and Risks

Parex is exposed to various market and operational risks. For a discussion of these risks please refer to the "Risk Factors" section in Parex's AIF for the year ended December 31, 2025 as filed on SEDAR+ at www.sedarplus.ca or Parex's website at www.parexresources.com.

Internal Controls over Financial Reporting

There has been no change in Parex's internal controls over financial reporting ("ICFR") or disclosure controls and procedures ("DC&P") during the period covered by this MD&A that materially affected, or is reasonably likely to materially affect, its ICFR or DC&P.

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the three months ended March 31, 2026 other than normal course guarantees entered into in the form of letters of credit to support the exploration work commitments on its blocks. For further information refer to "Contractual Obligations, Commitments and Guarantees" section above and note 25 - Commitments and Contingencies in the unaudited condensed interim consolidated financial statements.

Financial Instruments and Other Instruments

The Company's non-derivative financial instruments recognized in the consolidated balance sheet consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity.

Material Accounting Policies

The accounting policies adopted are consistent with those of the previous financial year as described in note 3 of the Company's consolidated financial statements for the year ended December 31, 2025 with the addition of the below Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures.

On January 1, 2026, the Company adopted the amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures in the interim period ending March 31, 2026. The amendments for disclosures relates to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. There was not a material effect the Company's condensed interim consolidated financial statements. The Company has applied the election to deem financial liabilities settled in cash using an electronic payment system to be discharged before the settlement date. The amendments have been applied retrospectively with no restatement of comparative information, in accordance with transition requirements on initial application of IFRS 9. There is no adjustment to the opening balance of cash and cash equivalents in the consolidated statements of cash flows.

Significant Accounting Estimates

The preparation of consolidated financial statements in accordance with IFRS requires management to make significant judgments, assumptions and estimates that affect the financial results of the Company. Refer to note 2 of the audited consolidated financial statements for a summary of significant accounting estimates applied by the Company.

DIRECTORS

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Glenn McNamara
Vice Chair

Lynn Azar

Alberto Consuegra

Sigmund Cornelius

Mona Jasinski

Jeff Lawson

G.R (Bob) MacDougall

Imad Mohsen

Carmen Sylvain

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President & Country Manager, Parex Resources (Colombia) AG Sucursal

Cameron Grainger
Chief Financial Officer

Eric Furlan
Chief Operating Officer

Mike Kruchten
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ABBREVIATIONS**Oil and Natural Gas Liquids**

bbl(s)	barrel(s)
mbbls	one thousand barrels
bbl(s)/d or bopd	barrel(s) of oil per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
boe/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice
FFO	Funds flow provided by operations