CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets (unaudited)

As at (thousands of United States dollars)	NOTE	**June 30, 2026**	December 31, 2025
ASSETS			
Current assets			
Cash and cash equivalents	**23**	**$ 163,286**	$ 58,328
Restricted cash and cash equivalents	**23**	**6,120**	5,424
Accounts receivable	**5**	**151,485**	78,329
Prepaids and other current assets		**35,506**	13,357
Marketable securities	**6**	**55,375**	45,090
Derivative financial instruments	**25**	**3,874**	776
Current income tax receivable		**145,149**	68,363
Short-term inventory	**7**	**41,452**	4,327
		602,247	273,994
Exploration and evaluation	**10**	**260,751**	161,125
Property, plant and equipment	**11**	**2,595,243**	1,500,213
Long-term inventory	**12**	**167,366**	175,426
Other long-term assets	**23**	**50,432**	14,629
Deferred tax asset		**486,039**	142,253
Goodwill		**73,452**	73,452
		$ 4,235,530	$ 2,341,092
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		**$ 608,873**	235,809
Current portion of customer prepayments	**13**	**$ 48,889**	—
Current portion of decommissioning and environmental liabilities	**16**	**27,707**	10,158
		685,469	245,967
Customer prepayments	**13**	**31,111**	—
Debt	**14**	**792,265**	33,000
Lease obligations	**15**	**17,728**	7,814
Decommissioning and environmental liabilities	**16**	**313,856**	79,007
Cash settled share-based compensation liabilities	**17**	**11,471**	15,228
Other long-term liabilities		**31,906**	7,143
		1,883,806	388,159
Shareholders' equity			
Share capital	**18**	**624,657**	621,062
Contributed surplus		**20,469**	20,738
Retained earnings		**1,706,598**	1,311,133
		2,351,724	1,952,933
		$ 4,235,530	$ 2,341,092

Commitments and Contingencies (note 27)
Subsequent Events (note 28)
See accompanying Notes to the Condensed Interim Consolidated Financial Statements

Approved by the Board:

"signed" Sigmund Cornelius Director	"signed" Bob MacDougall Director

Consolidated Statements of Net Income and Comprehensive Income (unaudited)

(thousands of United States dollars, except per share amounts)	NOTE	For the three months ended June 30, **2026**	2025	For the six months ended June 30, **2026**	2025
Oil and natural gas sales	**19**	**$ 466,016**	$ 239,070	**$ 737,393**	$ 504,705
Royalties		**(72,961)**	(30,913)	**(109,749)**	(67,318)
Net revenue		**393,055**	208,157	**627,644**	437,387
Other revenue	**19**	**2,909**	2,319	**4,664**	4,831
Commodity risk management contracts gain (loss)	**25**	**(76)**	1,530	**(31,897)**	967
Revenue		**395,888**	212,006	**600,411**	443,185
Expenses					
Production		**90,766**	49,492	**148,082**	106,350
Transportation		**34,019**	17,421	**54,276**	34,239
Purchased crude oil		**36,709**	(30)	**36,756**	162
General and administrative		**23,412**	16,684	**45,839**	34,455
Unrealized (gain) loss on marketable securities	**6**	**2,433**	—	**(10,285)**	—
Transaction costs	**8**	**28,390**	—	**29,000**	—
Gain on acquisition	**8**	**(302,483)**	—	**(302,483)**	—
Depletion, depreciation and amortization	**11**	**62,382**	47,949	**113,671**	98,368
Cash settled share-based compensation (recovery) expense	**17**	**(606)**	6,294	**17,887**	8,206
Equity settled share-based compensation expense	**18**	**265**	182	**439**	362
Other expense	**20**	**8,970**	12,453	**26,327**	13,600
Foreign exchange gain		**(4,568)**	(2,037)	**(2,481)**	(3,621)
		(20,311)	148,408	**157,028**	292,121
Finance (income)	**21**	**(2,740)**	(612)	**(6,144)**	(1,909)
Finance expense	**21**	**17,219**	5,474	**23,984**	10,530
Net finance expense		**14,479**	4,862	**17,840**	8,621
Income before income taxes		**401,720**	58,736	**425,543**	142,443
Income tax expense					
Current tax expense		**16,889**	9,245	**17,960**	21,132
Deferred tax (recovery) expense		**(59,465)**	378	**(41,302)**	(8,431)
		(42,576)	9,623	**(23,342)**	12,701
Net income and comprehensive income for the period		**$ 444,296**	$ 49,113	**$ 448,885**	$ 129,742
Basic net income per common share	**22**	**$ 4.62**	$ 0.50	**$ 4.67**	$ 1.33
Diluted net income per common share	**22**	**$ 4.61**	$ 0.50	**$ 4.66**	$ 1.33

See accompanying Notes to the Condensed Interim Consolidated Financial Statements

Consolidated Statements of Changes in Equity (unaudited)

For the six months ended June 30, (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		**3,595**		—
Repurchase of shares		**—**		(5,733)
Balance, end of period	**$**	**624,657**	$	627,166
Contributed surplus				
Balance, beginning of period	**$**	**20,738**	$	20,024
Share-based compensation		**439**		362
Options exercised		**(708)**		—
Balance, end of period	**$**	**20,469**	$	20,386
Retained earnings				
Balance, beginning of period	**$**	**1,311,133**	$	1,178,398
Net income for the period		**448,885**		129,742
Repurchase of shares		**—**		(5,531)
Dividends		**(53,420)**		(53,926)
Balance, end of period	**$**	**1,706,598**	$	1,248,683
	$	**2,351,724**	$	1,896,235

See accompanying Notes to the Condensed Interim Consolidated Financial Statements

Consolidated Statements of Cash Flows (unaudited)

(thousands of United States dollars)	NOTE	For the three months ended June 30, 2026	For the three months ended June 30, 2025	For the six months ended June 30, 2026	For the six months ended June 30, 2025
Operating activities					
Net income		**$ 444,296**	$ 49,113	**$ 448,885**	$ 129,742
Add (deduct) non-cash items					
Unrealized (gain) loss on marketable securities	**6**	**2,433**	—	**(10,285)**	—
Gain on acquisition	**8**	**(302,483)**	—	**(302,483)**	—
Non-cash inventory fair value adjustment	**8**	**9,365**	–	**9,365**	–
Depletion, depreciation and amortization	**11**	**62,382**	47,949	**113,671**	98,368
Cash settled share-based compensation expense (recovery)	**17**	**(606)**	6,294	**17,887**	8,206
Equity settled share-based compensation expense	**18**	**265**	182	**439**	362
Non-cash other expense	**20**	**4,955**	374	**5,254**	580
Non-cash finance expense	**21**	**3,764**	3,262	**6,882**	6,386
Deferred tax (recovery) expense		**(59,465)**	378	**(41,302)**	(8,431)
Unrealized foreign exchange gain		**(2,217)**	(2,369)	**(1,507)**	(7,288)
Unrealized gain on commodity risk management contracts	**25**	**(30,635)**	(362)	**(1,050)**	(1,160)
Net change in assets and liabilities	**23**	**67,181**	37,821	**(22,435)**	3,255
Cash provided by operating activities		**199,235**	142,642	**223,321**	230,020
Investing activities					
Exploration and evaluation expenditures	**10**	**(64,562)**	(39,623)	**(107,323)**	(51,726)
Property, plant and equipment expenditures	**11**	**(69,131)**	(49,067)	**(117,413)**	(94,018)
Long-term inventory expenditures, net of transfers and sales	**12**	**1,243**	3,667	**8,060**	8,315
Business acquisition, net of cash acquired	**8**	**(232,179)**	—	**(307,179)**	—
Property acquisition	**9**	**—**	—	**—**	(15,968)
Net change in non-cash working capital	**23**	**9,976**	25,885	**14,545**	31,244
Cash (used in) investing activities		**(354,653)**	(59,138)	**(509,310)**	(122,153)
Financing activities					
Issuance of unsecured notes, proceeds	**14**	**500,000**	—	**500,000**	—
Issuance costs of unsecured notes	**14**	**(15,380)**	—	**(15,380)**	—
Bank debt repayment	**14**	**(175,200)**	(32,000)	**(33,000)**	(42,000)
Payments on lease obligations	**15**	**(1,699)**	(172)	**(2,314)**	(218)
Dividends	**18**	**(26,483)**	(27,561)	**(53,420)**	(53,926)
Common shares repurchased	**18**	**—**	(6,025)	**—**	(11,264)
Issuance of common shares under equity-settled plans	**18**	**916**	—	**2,887**	—
Net change in non-cash working capital	**23**	**—**	(1,331)	**—**	(1,228)
Cash provided by (used in) financing activities		**282,154**	(67,089)	**398,773**	(108,636)
Increase (decrease) in cash and cash equivalents and restricted cash and cash equivalents for the period		**126,736**	16,415	**112,784**	(769)
Impact of foreign exchange on foreign currency-denominated cash balances		**4,944**	928	**5,525**	2,482
Cash and cash equivalents and restricted cash and cash equivalents, beginning of period	**23**	**50,572**	86,157	**63,943**	101,787
Cash and cash equivalents and restricted cash and cash equivalents, end of period	**23**	**$ 182,252**	$ 103,500	**$ 182,252**	$ 103,500

Supplemental Disclosure of Cash Flow Information (note 23)

See accompanying Notes to the Condensed Interim Consolidated Financial Statements

Notes to the Condensed Interim Consolidated Financial Statements

For the period ended June 30, 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 July 30, 2026.

2. Basis of Presentation and Material Accounting Policies

a) Statement of compliance

The condensed interim consolidated financial statements for the three and six months ended June 30, 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 July 30, 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 those items which are measured at fair value as 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 relate to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. There was not a material effect to 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.

In addition, due to the acquisition of Frontera Petroleum International Holdings B.V. (see Note 8 - Business Combination), the following additional accounting policies have been updated:

Subsidiaries:
Frontera Energy Colombia AG has been identified as an additional principal operating subsidiary. Frontera Energy AG is incorporated in Switzerland and its principle business activity is oil and natural gas exploration and development in Colombia. Parex has 100% ownership of this subsidiary.

Customer prepayments:
The Company recognizes each contract in the statement of financial position as either a contract asset or a contract liability, based on the relationship between the Company's performance under the contract and the consideration received from the customer. Additionally, when a customer pays consideration, or when the Company has an unconditional right to consideration (i.e., a receivable) before transferring goods or services, the entity shall present the amount as a contract liability or customer prepayment in the statement of financial position (see Note 13 - Customer Prepayments). This classification applies at the earlier of the payment date or the date the payment becomes due. Financing components embedded in customer prepayment arrangements are recognized using the effective interest method over the term of the agreement when significant financing components exist.

In addition, due to the recognition of Equity tax in the current period, the following additional accounting policy has been updated:

Equity tax:
Equity tax represents a tax imposed by the Colombian Government on entities whose net equity exceeds a prescribed threshold as of a specified measurement date. The tax is recognized as an expense when the obligating event occurs and the amount can be reliably estimated. The related liability is measured based on the applicable tax rate applied to taxable net equity, considering enacted or substantively enacted tax legislation at the reporting date. Equity tax is recognized in profit or loss and is not included in income tax expense unless required by applicable tax legislation (see Note 20 - Other Expense).

Standards Issued but not yet Effective

i) IFRS 18 Presentation and Disclosure in Financial Statements
In April 2024, the IASB issued IFRS 18 Presentation and Disclosure in Financial Statements ("IFRS 18") which will replace IAS 1 and includes requirements for all entities applying IFRS for the presentation and disclosure of information in the financial statements. IFRS 18 will introduce new totals, subtotals and categories for income and expenses in the statement of income, as well as requiring disclosure about management-defined performance measures ("MPMs") and additional requirements regarding the aggregation and disaggregation of certain information. The new guidance is expected to improve the usefulness of information presented and disclosed in the financial statements of companies. IFRS 18 will be effective for annual reporting periods beginning on or after January 1, 2027, with early adoption permitted, and it must be adopted on a retrospective basis.

Parex is currently assessing the impact of this new IFRS accounting standard on its consolidated financial statements. Throughout 2026, Parex will assess system changes, draft and finalize financial statements to quantify the impact of changes, MPMs and related disclosures ahead of the 2027 effective date.

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

		June 30, 2026		December 31, 2025
Trade receivables	**$**	**105,162**	$	72,317
Receivables from partners		**30,323**		—
Value added taxes (VAT)		**16,000**		6,012
	$	**151,485**	$	78,329

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. Receivables from partners primarily relate to amounts recoverable from joint venture partners for their share of costs incurred under joint operations. VAT receivable consists of value-added taxes paid on Colombian oil and gas operating, capital, and administrative expenditures that are recoverable from the Colombian tax authorities. All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Marketable Securities

		June 30, 2026		December 31, 2025
Marketable securities	**$**	**55,375**	$	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 June 30, 2026 was $55.4 million, resulting in an unrealized gain of $10.3 million, which is recorded in the consolidated statements of net income and comprehensive income.

7. Short-term Inventory

		June 30, 2026		December 31, 2025
Crude oil inventory	**$**	**26,220**	$	4,327
Materials inventory		**15,232**		—
Total	**$**	**41,452**	$	4,327

Crude oil inventory consists of crude injected into pipelines and stored in tanks 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.

Materials inventory consists of materials used in operations and is valued at the lower of cost and net realizable value.

8. Business Combination

Frontera Transaction

On June 1, 2026, the Company closed its previously announced acquisition of all the Colombian exploration and production assets of Frontera Energy Corporation, pursuant to which the Company, through a wholly-owned subsidiary, acquired 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 cash consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million (the "Frontera Transaction"). The Frontera Transaction was funded with the proceeds from the Company's issuance of senior unsecured notes, see Note 14 - Debt for details.

The contingent consideration is payable to Frontera if, within 12 months following the closing of the Frontera Transaction, the Company obtains a contractual amendment or other binding agreement extending the term of the Quifa Association Contract. At the acquisition date, the contingent consideration was recognized at its estimated fair value of $12.5 million, reflecting management's probability-weighted assessment of the payment condition being satisfied. As any payment, if triggered, is expected within 12 months of the acquisition date, the effect of discounting was not material.

The fair value measurement of the contingent consideration is classified within Level 3 of the fair value hierarchy because it uses significant unobservable inputs, principally the probability of obtaining the required contractual extension. The contingent consideration was remeasured at June 30, 2026, with no change in its fair value recognized during the period.

IFRS 3 requires the amounts to record for the underlying assets and liabilities acquired to be determined at the closing date (the "acquisition date") whereas the consideration for the business was negotiated earlier and voted on by the Frontera shareholders April 30, 2026. Furthermore, deferred tax assets are recorded at undiscounted amounts based on temporary differences existing at the acquisition date and are therefore not recorded at fair value under IFRS. The tax basis of the underlying assets acquired is in Colombian pesos which differs from the functional currency of the company and due to volatility in currencies this also significantly increased the US dollar equivalent value of the tax pools at the acquisition date relative to the time when the purchase was negotiated. As a result, the Company has estimated that the deferred tax assets contributed to the recognition of a bargain purchase gain approximating the deferred tax assets recognized.

The consolidated statements of net income and comprehensive income include results of operations of the Frontera Transaction since the closing date of June 1, 2026. The Company incurred transaction costs in connection with the Frontera Transaction of $28.4 million and $29.0 million for the three and six months ended June 30, 2026 respectively, which are expensed as incurred and presented in the consolidated statements of net income and comprehensive income.

The below amounts are estimates which were made by management at the time of the preparation of these condensed interim consolidated financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized for a period of up to one year. The pro forma information disclosed below is presented for informational purposes only and is not necessarily indicative of the results that would have been achieved had the Frontera Transaction occurred on January 1, 2026, nor is it indicative of future results.

The key assumptions used in the business combination to calculate the purchase price allocation include reserve estimates of proved plus probable reserves acquired that are based on production forecasts, future commodity prices, future development costs and future production costs.

As a result of the acquisition, the Company recognized a bargain purchase gain of $302.5 million, representing the excess of the fair value of the identifiable net assets acquired over the consideration transferred. The bargain purchase gain was recognized in the consolidated statements of net income and comprehensive income.

Before recognizing the bargain purchase gain, the Company assessed the completeness and accuracy of the assets acquired, liabilities assumed and consideration transferred, including the valuation methodologies and key assumptions applied in determining acquisition-date fair values, in accordance with IFRS 3.

The following table summarizes the recognizable assets acquired, liabilities assumed and consideration paid pursuant to the Frontera Transaction:

Assets acquired and liabilities assumed		
Assets		
Cash and cash equivalents	$	165,859
Restricted cash and cash equivalents		10,657
Accounts receivables		84,094
Prepaids and other current assets		11,181
Short-term inventory		67,569
Current income tax receivable		61,927
Exploration and evaluation assets		11,089
Property, plant and equipment		986,557
Right-of-use-asset		16,003
Other long-term assets		18,198
Deferred tax asset		302,483
Liabilities		
Accounts payable and accrued liabilities		(344,031)
Derivative financial instruments		(1,282)
Long-term debt - unsecured notes		(307,311)
Customer prepayments		(80,300)
Lease obligations		(16,003)
Decommissioning and environmental liabilities		(179,999)
Other long-term liabilities		(8,013)
Net assets acquired	**$**	**798,678**
Consideration transferred		(496,195)
Bargain purchase gain	**$**	**302,483**

Consideration for the acquisition		
Base purchase price	$	500,000
Purchase price adjustments		(16,305)
Cash consideration paid at closing		483,695
Fair value of contingent consideration		12,500
Total consideration	**$**	**496,195**
Cash paid	$	483,695
Less: Cash and cash equivalents acquired		(176,516)
Net cash outflow on acquisition	**$**	**307,179**

The pro forma results for the six month period ended June 30, 2026 are shown below, as if the Frontera Transaction had occurred on January 1, 2026. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	$	1,205,557
Net revenue less direct costs	$	569,531

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 net income and comprehensive income for the six months ended June 30, 2026 includes $129.5 million of oil and natural gas sales attributable to the assets acquired since the Frontera Transaction. Revenue less direct costs for the six months ended June 30, 2026 attributable to the assets acquired since the Frontera Transaction is $39.7 million.

9. 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 statements of net income and 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 six month period ended June 30, 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	$	508,468
Net revenue less direct costs	$	299,815

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 net income and comprehensive income for the six months ended June 30, 2025 includes $11.3 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the six months ended June 30, 2025 attributable to the assets acquired since the LLA-32 Acquisition is $7.3 million.

10. 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		107,323
Acquired on close of business combination - Note 8		11,089
Transfers to PP&E		(28,961)
Changes in decommissioning liability		10,175
Balance at June 30, 2026	**$**	**260,751**

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 $107.3 million for the six months ended June 30, 2026 represent the Company's share of costs incurred on E&E assets during the period. During the six months ended June 30, 2026, $29.0 million of E&E assets were transferred to PP&E related to Block LLA-111.

For the six months ended June 30, 2026 $1.1 million of general and administrative costs (six months ended June 30, 2025 - $1.2 million) have been capitalized in respect of exploration and evaluation activities during the current period.

At June 30, 2026 and December 31, 2025 the Company did not have any E&E assets in Canada.

At June 30, 2026 there were no indicators of impairment noted.

11. Property, Plant and Equipment

		Canada		Colombia		Total
Cost						
Balance at December 31, 2024	**$**	**21,432**	**$**	**3,756,897**	**$**	**3,778,329**
Additions and transfers from long-term inventory		1,340		199,255		200,595
Right-of-use-asset addition (non-cash)		—		4,338		4,338
Transfers from E&E assets		—		60,020		60,020
Additions related to property acquisition - Note 9		—		16,788		16,788
Changes in decommissioning and environmental liability		—		372		372
Balance at December 31, 2025	**$**	**22,772**	**$**	**4,037,670**	**$**	**4,060,442**
Additions and transfers from long-term inventory		411		117,002		117,413
Right-of-use-asset addition (non-cash) - Note 8		—		16,003		16,003
Transfers from E&E assets		—		28,961		28,961
Acquired on close of business combination - Note 8		—		986,557		986,557
Changes in decommissioning and environmental liability		—		59,584		59,584
Balance at June 30, 2026	**$**	**23,183**	**$**	**5,245,777**	**$**	**5,268,960**
Accumulated Depreciation, Depletion and Amortization						
Balance at December 31, 2024	**$**	**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**	**$**	**2,560,229**
Depletion and depreciation for the period		1,158		111,231		112,389
Depreciation - Right-of-use-asset		377		905		1,282
DD&A included in crude oil inventory costing		—		(183)		(183)
Balance at June 30, 2026	**$**	**17,100**	**$**	**2,656,617**	**$**	**2,673,717**
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 June 30, 2026	**$**	**6,083**	**$**	**2,589,160**	**$**	**2,595,243**

In the six months ended June 30, 2026 property, plant and equipment ("PPE") additions of $117.4 million mainly relate to drilling and facility costs in Colombia. During the six months ended June 30, 2026, $29.0 million of E&E assets were transferred to PP&E related to Block LLA-111.

For the six months ended June 30, 2026 future development costs of $836.0 million (six months ended June 30, 2025 - $378.0 million) were included in the depletion calculation for development and production assets. For the six months ended June 30, 2026 $3.7 million of general and administrative costs (six months ended June 30, 2025 - $3.6 million) have been capitalized in respect of development and production activities during the current period.

At June 30, 2026 there were no indicators of impairment noted, or indicators requiring a reversal of previously recorded impairments.

12. Long-term Inventory

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

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		7,224
Transfers to E&E and PP&E assets		(14,558)
Sale of inventory		(726)
Balance at June 30, 2026	**$**	**167,366**

For the six months ended June 30, 2026, long-term inventory additions were $7.2 million, $14.6 million of long-term inventory was incorporated into the costs of E&E and PP&E projects and $0.7 million of inventory was sold. At June 30, 2026 there were no indicators of impairment noted.

13. Customer prepayments

		June 30, 2026		December 31, 2025
Current portion of customer prepayments	**$**	**48,889**	$	—
Non-current portion of customer prepayments		**31,111**		—
Total customer prepayments	**$**	**80,000**	$	—

In conjunction with the Frontera Transaction, the Company assumed all of Frontera’s obligations under its customer prepayments. In December 2025, Frontera entered into a 24-month agreement with Chevron Products Company ("Chevron") to supply 500,000 barrels of crude oil per month. An advance payment of $80 million was received and recorded as a customer prepayment, to be recognized as revenue upon monthly deliveries. The sales price will be based on the Brent reference price, adjusted for applicable differentials and discounts, and repayment of the prepayment amount will begin after a six-month grace period. The Company may request an additional $40 million advance for up to six months on a fully committed basis. Under the agreement, the prepayment amounts will be subject to a financial discount calculated at SOFR plus 4.25% per annum.

As at June 30, 2026, customer prepayments are principally attributable to the advance payment received under the crude oil supply agreement described above. As at June 30, 2026, the carrying value for customer prepayments was $80.0 million, which includes short-term prepayments of $48.9 million.

14. Debt

		June 30, 2026		December 31, 2025
2031 Unsecured notes	$	**484,953**	$	—
2028 Unsecured notes		**307,312**		—
Total Unsecured notes		**792,265**		—
Credit facility		**—**		33,000
Total debt	$	**792,265**	$	33,000

Unsecured Notes

2031 Unsecured Notes

On May 11, 2026, in conjunction with the Frontera Transaction, the Company completed a $500.0 million private placement offering of senior unsecured notes due 2031 ("2031 Unsecured Notes") 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, unless earlier redeemed or repurchased. The interest is payable semi-annually in arrears on November 11 and May 11 of each year, beginning on November 11, 2026. The carrying value for the 2031 Unsecured Notes as at June 30, 2026 was $485.0 million compared to the fair value of $508.0 million (Level 2 input).
Net proceeds from the sale of the Notes were $484.6 million, after deducting the initial offering expenses payable by the Company of $15.4 million.

Key covenants include a fixed charge test of not less than 2.25:1 and net 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 June 30, 2026.

2028 Unsecured Notes

In conjunction with the Frontera Transaction, the Company assumed all of Frontera's obligations under its $310.0 million aggregate principal amount of 7.875% senior unsecured notes due 2028 ("2028 Unsecured Notes") issued on June 21, 2021. The interest is payable semi-annually in arrears on June 21 and December 21 of each year, beginning on December 21, 2021. The 2028 Unsecured Notes will mature June 21, 2028, unless earlier redeemed or repurchased. The carrying value for the 2028 Unsecured Notes as at June 30, 2026 was $307.3 million compared to the fair value of $308.8 million (Level 2 input).

Key covenants include a fixed charge test of not less than 2.25:1 and net debt to adjusted EBITDA test of 3.25:1 and other standard business operating covenants for each reporting period. The Company was in compliance with all key covenants at June 30, 2026.

The 2028 and 2031 unsecured notes are subordinated to secured debt to the extent of the value of the assets securing such indebtedness.

Credit Facility

The Company has a senior secured credit facility with a syndicate of banks which at June 30, 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 June 30, 2026, there was no draw on the credit facility (at December 31, 2025 - $33.0 million was drawn). The undrawn capacity on the credit facility at June 30, 2026 was $240.0 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 31, 2028. The next annual review is scheduled to occur in May 2027.

Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3.50:1, senior secured debt to adjusted EBITDA test of 3.00:1, and other standard business operating covenants for each reporting period. The Company was in compliance with all key covenants at June 30, 2026.

Refer to note 27 – 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.

15. 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**
Acquired on close of business combination - Note 8		—		16,003		16,003
Interest expense		16		431		447
Lease payments		(362)		(2,399)		(2,761)
Foreign exchange loss (gain)		(134)		216		82
Balance at June 30, 2026	**$**	**3,198**	**$**	**19,718**	**$**	**22,916**
Current obligation		(739)		(4,449)		(5,188)
Long-term obligation	**$**	**2,459**	**$**	**15,269**	**$**	**17,728**

In connection with the Frontera Transaction, the Company assumed Frontera's obligations under its existing lease arrangements. The leases relate to various properties, vehicles, power generation supply, including the arrangements associated to the CPE-6 Solar Plant and CPE-6 Battery Energy Storage System, and other assets.

16. 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 9		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		10,772		2,723		13,495
Acquired on close of business combination - Note 8		156,249		23,750		179,999
Discount rate adjustment on obligations acquired		32,355		5,894		38,249
Settlements of obligations during the period		(8,614)		(2,450)		(11,064)
Gain on settlement of obligations		(1,046)		(175)		(1,221)
Accretion expense		5,442		826		6,268
Change in estimate - inflation and discount rates		17,830		4,264		22,094
Change in estimate - costs and timing of settlements		(5,014)		935		(4,079)
Foreign exchange loss		5,537		3,120		8,657
Balance, June 30, 2026	**$**	**291,074**	**$**	**50,489**	**$**	**341,563**
Current obligation		(18,572)		(9,135)		(27,707)
Long-term obligation	**$**	**272,502**	**$**	**41,354**	**$**	**313,856**

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 June 30, 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 $641.6 million as at June 30, 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 11.4% 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 $18.6 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 $100.4 million as at June 30, 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 11.4% 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 $9.1 million (December 31, 2025 – $2.8 million) that is classified as a current obligation.

17. 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]	495,727	—
Exercised	(624,659)	—
Forfeited	(113,660)	—
Balance, June 30, 2026	**1,253,843**	**—**

(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]	68,808	—
Granted by performance factor	235,720	—
Exercised	(532,633)	—
Forfeited	(68,555)	—
Balance, June 30, 2026	**251,439**	**—**

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

As at June 30, 2026 and 2025, no CosRSUs and CosPSUs were vested.

The weighted average fair value at the grant date for the six months ended June 30, 2026 was Cdn$26.26 per CosRSU and CosPSU (six months ended June 30, 2025 - Cdn$12.71 per CosRSU and CosPSU). The weighted average share price on the exercise date for CosRSUs and CosPSUs exercised during the six months ended June 30, 2026 was Cdn$21.95 (six months ended June 30, 2025 – Cdn$13.67).

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 June 30, 2026, the total CosRSUs and CosPSUs liability accrued is $8.3 million (December 31, 2025 - $18.8 million) of which $2.8 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 ten years from the date of grant. LDPSUs vest three years after the grant date and expire ten years after 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]	104,705	—
Exercised	(14,500)	—
Balance, June 30, 2026	**401,653**	**—**

(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]	210,255	—
Balance, June 30, 2026	**833,153**	**—**

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

As at June 30, 2026 129,578 LDRSUs and no LDPSUs were vested. As at June 30, 2025 36,779 LDRSUs and no LDPSUs were vested.

The weighted average fair value at the grant date for the six months ended June 30, 2026 was Cdn$26.32 per LDRSU and LDPSU (six months ended June 30, 2025 - Cdn$12.75 per LDRSU and LDPSU). The weighted average share price on the exercise date for LDRSUs exercised during the six months ended June 30, 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 ten 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 June 30, 2026, the total LDRSUs and LDPSUs liability accrued is $6.9 million (December 31, 2025 - $4.0 million) of which $1.8 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)	42,473	—
Exercised on board retirement	(119,060)	—
Balance, June 30, 2026	**332,079**	—

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

The weighted average fair value at the grant date for the six months ended June 30, 2026 was $21.39 per DSU (six months ended June 30, 2025 - Cdn$10.88 per DSU). The weighted average share price on the exercise date for DSUs exercised during the six months ended June 30, 2026 was Cdn $20.77. There were no DSUs exercised in the six months ended June 30, 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 June 30, 2026, the total DSUs liability accrued is $5.0 million (December 31, 2025 - $5.5 million) of which $4.7 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)	489,027	—
Exercised	(550,302)	—
Forfeited	(84,687)	—
Balance, June 30, 2026	**1,212,800**	**—**

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

The weighted average fair value at the grant date for six months ended June 30, 2026 was Cdn$23.14 per CRSU (six months ended June 30, 2025 - Cdn$12.74 per CRSU). The weighted average share price on the exercise date for CRSUs exercised for the six months ended June 30, 2026 was Cdn$21.73 (six months ended June 30, 2025 – Cdn$13.90).

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 June 30, 2026, the total CRSUs liability accrued is $7.0 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 June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
CosRSUs and CosPSUs expense	**$ 1,547**	$ 2,837	**$ 8,574**	$ 4,629
LDRSUs and LDPSUs expense (recovery)	**(626)**	592	**3,109**	831
DSUs expense (recovery)	**(781)**	1,322	**1,596**	1,143
CRSUs expense (recovery)	**(746)**	1,543	**4,608**	1,603
Total cash settled share-based compensation expense (recovery)	**$ (606)**	$ 6,294	**$ 17,887**	$ 8,206
Cash payments made upon exercise in the period	**$ 3,425**	$ 518	**$ 29,577**	$ 11,232

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	206,118	2,887
Allocation of contributed surplus – exercise of options	—	708
Balance, June 30, 2026	**96,180,254**	**$ 624,657**

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

In the six months ended June 30, 2026, there were 206,118 options exercised for proceeds of $2.9 million (year ended December 31, 2025 - no options were exercised). For the six months ended June 30, 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 $53.4 million or Cdn$0.77 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	(206,118)	19.31
Forfeited	(168,583)	20.97
Balance, June 30, 2026	**1,220,293**	**20.24**

Stock options outstanding and the weighted average remaining life of the stock options at June 30, 2026 are as follows:

	Options outstanding			Options vested		
Exercise price Cdn$	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	433,177	3.69	$ 12.74	96,894	3.69	$ 12.74
$16.91 - $21.92	194,028	2.68	$ 21.06	116,869	2.68	$ 21.06
$21.93 - $25.60	116,804	1.60	$ 22.81	116,804	1.60	$ 22.81
$25.61 - $26.37	341,386	4.70	$ 25.72	—	—	$ —
$26.38 - $27.02	134,898	0.61	$ 27.02	134,898	0.61	$ 27.02
	1,220,293	**3.27**	**$ 20.24**	**465,465**	**2.02**	**$ 21.50**

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 six months ended June 30,	**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 (%)	**7.20**	11.07

The weighted average fair value at the grant date for the six months ended June 30, 2026 was Cdn$5.76 per option (six months ended June 30, 2025 - Cdn$1.68 per option). In the six months ended June 30, 2026, there were 206,118 options exercised. The weighted average share price on the exercise date for options exercised in the six months ended June 30, 2026 was $27.01.

c) Equity settled share-based compensation

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Option expense	**$ 265**	$ 182	**$ 439**	$ 362
Total equity settled share-based compensation expense	**$ 265**	$ 182	**$ 439**	$ 362

19. 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 June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Crude oil	**$ 455,076**	$ 232,465	**$ 717,530**	$ 492,342
Natural gas	**10,940**	6,605	**19,863**	12,363
Oil and natural gas sales	**$ 466,016**	$ 239,070	**$ 737,393**	$ 504,705

At June 30, 2026, receivables from contracts with customers, which are included in accounts receivable, were $105.2 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 June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Other revenue	**$ 2,909**	$ 2,319	**$ 4,664**	$ 4,831

20. Other Expense

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Other Colombian taxes	**$ 622**	$ 2,545	**$ 2,203**	3,326
Colombian tax credit purchased	**—**	8,097	**—**	8,097
Equity tax	**(712)**	—	**6,288**	—
Legal provisions	**1,343**	—	**1,519**	—
(Gain) loss on settlement of decommissioning liabilities	**(1,205)**	357	**(1,221)**	545
Loss on disposition of tangible assets	**4,232**	17	**4,371**	35
Site restoration costs	**4,234**	—	**10,803**	—
Other	**456**	1,437	**2,364**	1,597
Total other expense	**$ 8,970**	$ 12,453	**$ 26,327**	$ 13,600

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Non-cash other expense	**$ 4,955**	$ 374	**$ 5,254**	$ 580
Cash other expense	**4,015**	12,079	**21,073**	13,020
Total other expense	**$ 8,970**	$ 12,453	**$ 26,327**	$ 13,600

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 payable was settled by June 30, 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.

21. Net Finance Expense

		For the three months ended June 30,			For the six months ended June 30,	
		2026	2025		**2026**	2025
Bank charges and credit facility fees	**$**	**1,008**	$ 1,402	**$**	**2,226**	$ 2,191
Interest on bank debt		**3,052**	465		**4,826**	1,234
Interest on senior unsecured notes		**7,853**	—		**7,853**	—
Amortization of deferred note issuance costs		**333**	—		**333**	—
Accretion on decommissioning and environmental liabilities		**3,624**	3,316		**6,268**	6,538
Interest and other income		**(2,740)**	(612)		**(6,144)**	(1,909)
Lease obligation interest expense		**268**	46		**447**	93
Expected credit loss provision (recovery)		**139**	(50)		**613**	(149)
Other		**942**	295		**1,418**	623
Net finance expense	**$**	**14,479**	$ 4,862	**$**	**17,840**	$ 8,621

		For the three months ended June 30,			For the six months ended June 30,	
		2026	2025		**2026**	2025
Non-cash finance expense	**$**	**3,764**	$ 3,262	**$**	**6,882**	$ 6,386
Cash finance expense		**10,715**	1,600		**10,958**	2,235
Net finance expense	**$**	**14,479**	$ 4,862	**$**	**17,840**	$ 8,621

22. Net Income per Share

a) Basic net income per share

		For the three months ended June 30,			For the six months ended June 30,	
		2026	2025		**2026**	2025
Net income						
Net income for the purpose of basic net income per share	**$**	**444,296**	$ 49,113	**$**	**448,885**	$ 129,742
Weighted average number of shares for the purposes of basic net income per share (000s)		**96,179**	97,501		**96,086**	97,806
Basic net income per share	**$**	**4.62**	$ 0.50	**$**	**4.67**	$ 1.33

b) Diluted net income per share

		For the three months ended June 30,			For the six months ended June 30,	
		2026	2025		**2026**	2025
Net income						
Net income used to calculate diluted net income per share	**$**	**444,296**	$ 49,113	**$**	**448,885**	$ 129,742
Weighted average number of shares for the purposes of basic net income per share (000s)		**96,179**	97,501		**96,086**	97,806
Dilutive effect of stock options on potential common shares		**261**	—		**219**	—
Weighted average number of shares for the purposes of diluted net income per share (000s)		**96,440**	97,501		**96,305**	97,806
Diluted net income per share	**$**	**4.61**	$ 0.50	**$**	**4.66**	$ 1.33

For the three and six months ended June 30, 2026, 478,130 stock options (three and six months ended June 30, 2025 - 1,288,323 stock options) were excluded from the diluted weighted average shares calculation as they were anti-dilutive.

23. 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 June 30,		As at March 31,		As at December 31,	
	2026	2025	2026	2025	2025	2024
Cash and cash equivalents	**$ 163,286**	$ 98,825	$ 44,775	$ 81,025	$ 58,328	$ 98,022
Restricted cash and cash equivalents - current	**6,120**	597	5,504	619	5,424	581
Restricted cash and cash equivalents - long-term[1]	**12,846**	4,078	293	4,513	191	3,184
	$ 182,252	$ 103,500	$ 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 June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Accounts receivable	**$ 72,473**	$ 39,812	**$ 10,938**	$ 17,912
Prepaids and other current assets	**(6,516)**	3,794	**(10,968)**	1,671
Short-term inventory	**22,211**	1,060	**21,079**	1,808
Current income tax receivable/payable	**(18,016)**	(2,986)	**(14,859)**	(9,983)
Accounts payable and accrued liabilities	**16,255**	22,388	**(2,533)**	26,629
Customer prepayments	**(300)**	—	**(300)**	—
Depletion related to oil inventory	**(439)**	(327)	**(183)**	(546)
Decommissioning and environmental liabilities	**(8,511)**	(1,366)	**(11,064)**	(4,220)
Net change in assets and liabilities	**$ 77,157**	$ 62,375	**$ (7,890)**	$ 33,271
Operating	**$ 67,181**	$ 37,821	**$ (22,435)**	$ 3,255
Investing	**9,976**	25,885	**14,545**	31,244
Financing	**—**	(1,331)	**—**	(1,228)
Net change in assets and liabilities	**$ 77,157**	$ 62,375	**$ (7,890)**	$ 33,271

c) Interest and taxes paid

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Cash interest paid	**$ 14,505**	$ 625	**$ 15,661**	$ 1,682
Cash income taxes paid	**$ —**	$ —	**$ —**	$ —

24. Capital Management

The Company's objective when managing capital is to maintain a strong capital base that provides financial flexibility to fund operations, execute its business strategy and maintain the confidence of investors, lenders and other capital providers.

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 to include shareholders' equity, the credit facility, unsecured notes and its working capital. As at June 30, 2026 shareholders' equity was $2,351.7 million (December 31, 2025 - $1,952.9 million).

The Company has a senior secured credit facility with a syndicate of banks with a borrowing base of $240.0 million at June 30, 2026 (December 31, 2025 - $240.0 million). The credit facility is intended to provide additional liquidity and fund cash or letter of credit needs as they arise. As at June 30, 2026 there was no draw on the credit facility (at December 31, 2025 - $33.0 million was drawn).

Refer to note 14 - Debt for details regarding the Company's senior secured credit facility and senior unsecured notes.

Refer to note 27 – 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 June 30, 2026, the Company's net working capital deficit was $83.2 million (December 31, 2025 - $28.0 million surplus).

The Company is subject to financial covenants under its senior secured credit facility and senior unsecured notes. As at June 30, 2026, the Company was in compliance with all externally imposed capital requirements.

25. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash and cash equivalents, accounts receivable, marketable securities, accounts payable and accrued liabilities, the senior secured credit facility and senior unsecured notes. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to the short-term nature of these instruments. The fair value of the revolving credit facility approximates its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates. The fair value of the senior unsecured notes is determined based on quoted market prices and other observable market inputs and is classified as Level 2 within the fair value hierarchy. Refer to note 14 - Debt for the carrying values and fair values of the Company's senior unsecured notes as at June 30, 2026.

As at June 30, 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 $19.9 million.

a) Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The Company's exposure to credit risk primarily arises from cash and cash equivalents and accounts receivable from joint venture partners and oil marketing counterparties.

The Company manages credit risk related to cash and cash equivalents by maintaining balances with reputable financial institutions, monitoring the creditworthiness of banking counterparties, and assessing counterparty exposure.

The Company manages credit risk associated with accounts receivable by assessing the financial strength and creditworthiness of oil marketing counterparties and joint venture partners, monitoring outstanding balances, and evaluating the collectability of amounts owed to the Company.

For the six months ended June 30, 2026 the Company had the majority of its oil sales to one counterparty. The accounts receivable balance as at June 30, 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 June 30, 2026, there were no accounts receivable past due (December 31, 2025 - $nil). None of the Company's receivables are impaired at June 30, 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 maintain sufficient cash balances, cash flows from operations, available credit facilities and access to debt to meet its obligations as they become due. Management prepares cash flow forecasts for a period of 12 to 36 months to identify any financing requirements and monitor liquidity. 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. During the six months ended June 30, 2026, the Company issued $500.0 million aggregate principal amount of 8.50% senior unsecured notes due 2031. In addition, as at June 30, 2026, there was no draw on the Company's $240.0 million senior secured credit facility (December 31, 2025 - $33.0 million was drawn).

The following are the contractual maturities of financial liabilities at June 30, 2026:

	Less than 1 year	1-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	$ 588,033	—	—	31,906	$ 619,939
Unsecured notes, including interest	66,913	419,414	585,000	—	1,071,327
Customer prepayments	48,889	31,111			80,000
Lease obligation	5,188	17,728	—	—	22,916
Cash settled share-based compensation payable	15,652	11,471	—	—	27,123
Total	**$ 724,675**	**479,724**	**585,000**	**31,906**	**$ 1,821,305**

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 June 30, 2026, the Company had the no crude oil risk management contracts in place. The Company is currently unhedged for the remainder of 2026, with full exposure to changes in commodity prices.

The table below summarizes the loss (gain) on the commodity risk management contracts that were in place during the three and six months ended June 30, 2026 and 2025:

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Realized loss (gain) on commodity risk management contracts	**$ 30,711**	$ (3,337)	**$ 32,947**	$ (3,337)
Premiums paid on commodity risk management contracts	**—**	2,169	**—**	3,530
Unrealized gain on commodity risk management contracts	**(30,635)**	(362)	**(1,050)**	(1,160)
Total loss (gain)	**$ 76**	$ (1,530)	**$ 31,897**	$ (967)

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 June 30, 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
June 19, 2026 to December 15, 2026	COP	Costless collar	$90,000,000	3,400-3,663	N/A

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three and six months ended June 30, 2026 and 2025 which is recorded in the financial statement line item "Foreign exchange gain" in the consolidated statements of net income and comprehensive income:

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Realized gain on foreign currency risk management contracts	**$ (1,670)**	$ (1,225)	**$ (1,777)**	$ (1,225)
Unrealized gain on foreign currency risk management contracts	**(4,026)**	(4,132)	**(4,107)**	(4,132)
Total	**$ (5,696)**	$ (5,357)	**$ (5,884)**	$ (5,357)

26. Segmented Information

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

For the three months ended June 30, 2026	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 466,016	$ 466,016
Royalties	—	(72,961)	(72,961)
Net revenue	—	393,055	393,055
Other revenue	—	2,909	2,909
Commodity risk management contracts loss	—	(76)	(76)
Revenue	—	395,888	395,888
Expenses			
Production	—	90,766	90,766
Transportation	—	34,019	34,019
Purchased oil	—	36,709	36,709
General and administrative	8,494	14,918	23,412
Equity settled share-based compensation expense	265	—	265
Cash settled share-based compensation expense	140	(746)	(606)
Depletion, depreciation and amortization	765	61,617	62,382
Transaction costs	26,189	2,201	28,390
Other expenses	213	8,757	8,970
Foreign exchange (gain)	(921)	(3,647)	(4,568)
Unrealized loss on marketable securities	2,433	—	2,433
Gain on acquisition	(302,483)	—	(302,483)
	(264,905)	244,594	(20,311)
Finance (income)	(1,883)	(857)	(2,740)
Finance expense	11,354	5,865	17,219
Net finance expense	9,471	5,008	14,479
Income (loss) before taxes	255,434	146,286	401,720
Current tax expense	(1,009)	17,898	16,889
Deferred tax (recovery)	18	(59,483)	(59,465)
Net income (loss)	**$ 256,425**	**$ 187,871**	**$ 444,296**
Capital assets (end of period)	$ 6,083	$ 2,849,911	$ 2,855,994
Capital expenditures	$ 220	$ 133,473	$ 133,693
Total assets (end of period)	$ 128,051	$ 4,107,479	$ 4,235,530

For the three months ended June 30, 2025	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 239,070	$ 239,070
Royalties	—	(30,913)	(30,913)
Net revenue	—	208,157	208,157
Other revenue	—	2,319	2,319
Commodity risk management contracts gain	—	1,530	1,530
Revenue	—	212,006	212,006
Expenses			
Production	—	49,492	49,492
Transportation	—	17,421	17,421
Purchased oil	—	(30)	(30)
General and administrative	8,097	8,587	16,684
Equity settled share-based compensation expense	182	—	182
Cash settled share-based compensation expense	4,751	1,543	6,294
Depletion, depreciation and amortization	709	47,240	47,949
Other expenses	—	12,453	12,453
Foreign exchange (gain) loss	1,684	(3,721)	(2,037)
	15,423	132,985	148,408
Finance (income)	(84)	(528)	(612)
Finance expense	1,725	3,749	5,474
Net finance expense	1,641	3,221	4,862
Income (loss) before taxes	(17,064)	75,800	58,736
Current tax expense (recovery)	(139)	9,384	9,245
Deferred tax expense (recovery)	(1,162)	1,540	378
Net income (loss)	**$ (15,763)**	**$ 64,876**	**$ 49,113**
Capital assets (end of period)	$ 7,633	$ 1,592,939	$ 1,600,572
Capital expenditures	$ 129	$ 88,561	$ 88,690
Total assets (end of period)	$ 44,259	$ 2,178,919	$ 2,223,178

For the six months ended June 30, 2026	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 737,393	$ 737,393
Royalties	—	(109,749)	(109,749)
Net revenue	—	627,644	627,644
Other revenue	—	4,664	4,664
Commodity risk management contracts loss	—	(31,897)	(31,897)
Revenue	—	600,411	600,411
Expenses			
Production	—	148,082	148,082
Transportation	—	54,276	54,276
Purchased oil	—	36,756	36,756
General and administrative	20,036	25,803	45,839
Equity settled share-based compensation expense	439	—	439
Cash settled share-based compensation expense	13,279	4,608	17,887
Depletion, depreciation and amortization	1,535	112,136	113,671
Transaction costs	26,799	2,201	29,000
Other expense	885	25,442	26,327
Foreign exchange loss	422	(2,903)	(2,481)
Unrealized gain on marketable securities	(10,285)	—	(10,285)
Gain on acquisition	(302,483)	—	(302,483)
	(249,373)	406,401	157,028
Finance (income)	(1,927)	(4,217)	(6,144)
Finance expense	13,826	10,158	23,984
Net finance expense	11,899	5,941	17,840
Income (loss) before taxes	237,474	188,069	425,543
Current tax expense (recovery)	(6,403)	24,363	17,960
Deferred tax expense	1,072	(42,374)	(41,302)
Net income (loss)	**$ 242,805**	**$ 206,080**	**$ 448,885**
Capital assets (end of period)	$ 6,083	$ 2,849,911	$ 2,855,994
Capital expenditures	$ 411	$ 224,325	$ 224,736
Total assets (end of period)	$ 128,051	$ 4,107,479	$ 4,235,530

For the six months ended June 30, 2025	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 504,705	$ 504,705
Royalties	—	(67,318)	(67,318)
Net revenue	—	437,387	437,387
Other revenue	—	4,831	4,831
Commodity risk management contracts gain	—	967	967
Revenue	—	443,185	443,185
Expenses			
Production	—	106,350	106,350
Transportation	—	34,239	34,239
Purchased oil	—	162	162
General and administrative	15,787	18,668	34,455
Equity settled share-based compensation expense	362	—	362
Cash settled share-based compensation expense	6,603	1,603	8,206
Depletion, depreciation and amortization	1,510	96,858	98,368
Other expense	—	13,600	13,600
Foreign exchange (gain) loss	1,667	(5,288)	(3,621)
	25,929	266,192	292,121
Finance (income)	(214)	(1,695)	(1,909)
Finance expense	2,857	7,673	10,530
Net finance expense	2,643	5,978	8,621
Income (loss) before taxes	(28,572)	171,015	142,443
Current tax expense (recovery)	(1,139)	22,271	21,132
Deferred tax (recovery) expense	100	(8,531)	(8,431)
Net income (loss)	**$ (27,533)**	**$ 157,275**	**$ 129,742**
Capital assets (end of period)	$ 7,633	$ 1,592,939	$ 1,600,572
Capital expenditures	$ 224	$ 145,520	$ 145,744
Total assets (end of period)	$ 44,259	$ 2,178,919	$ 2,223,178

For the three months ended June 30, 2026, the Company had two external customers (three months ended June 30, 2025 - three 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 $365.0 million for the three months ended June 30, 2026 and $227.0 million for the three months ended June 30, 2025.

For the six months ended June 30, 2026, the Company had one external customer (six months ended June 30, 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 $475.8 million for the six months ended June 30, 2026 and $409.6 million for the six months ended June 30, 2025.

27. Commitments and Contingencies

The value of the Company’s commitments as at June 30, 2026 for contracts that were in place.

	2026	2027	2028	2029	2030	Thereafter	Total
Exploration and Evaluation							
Minimum work commitments	$ 40,655	$ 143,911	$ 104,155	$ 11,689	$ —	$ 405,504	$ 705,914
Transportation	13,884	2,554	—	—	—	—	16,438
Operating leases	1,228	2,271	623	—	—	—	4,122
Other commitments							
Purchased oil	58,325	—	—	—	—	—	58,325
Energy supply commitments	16,630	12,537	13,109	8,249	8,495	8,741	67,761
Total	**$ 130,722**	**$ 161,273**	**$ 117,887**	**$ 19,938**	**$ 8,495**	**$ 414,245**	**$ 852,560**

Exploration and evaluation minimum work commitments

At June 30, 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 $504.1 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 June 30, 2026 in respect of the Colombia work commitments under E&P contracts, and joint venture farm-in arrangements, is as disclosed above.

Transportation

Includes ship-or-pay contracts with Bicentenario and Cenit where the pledged inventory crude oil is stored in Cenit’s terminal of Coveñas (TLU-3) instead of Ocensa’s terminal. A pledge agreement with Ocensa and Cenit is in place, which guarantees the payment obligations of both contracts.

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 June 30, 2026 are as disclosed above.

Purchased oil

Includes an agreement in place covering crude oil purchases for 2026.

Energy supply

Includes executed contracts for grid-connected, on-site generation, and solar power sources, ensuring the electricity supply across operational blocks, particularly Quifa and CPE-6.

Contingencies

The Company is involved in various legal, regulatory and administrative claims, and proceedings arising from the normal course of business. Given that the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company’s favour. Management has assessed the likelihood of settlement and determined the best estimate based on relevant information and the probability of outcomes. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

Refer to Note 8 - Business Combinations regarding the contingent payment agreed to as part of the consideration of the Frontera Transaction.

28. Subsequent Events

Ecopetrol Strategic Partnership

Previously, on May 4, 2026, the Company announced that it had executed an agreement with its strategic partner Ecopetrol S.A., whereby the Company will earn a 50% participating share in the Casabe and Llanito blocks in the Magdalena Basin of Colombia, upon spudding the first well on each block. The agreement closed as of July 29, 2026, and all regulatory approvals received.

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 June 30, 2026 is dated July 30, 2026 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the period ended June 30, 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 the largest independent oil and gas company 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 June 30, 2026 ("second quarter" or "Q2") Highlights

- On June 1, 2026, the Company successfully closed its previously announced acquisition of all the Colombian exploration and production assets of Frontera Energy Corporation, becoming Colombia's largest independent oil and gas producer. The cash consideration was funded through the issuance of $500 million aggregate principal amount of 8.5% senior unsecured notes due 2031.
- Crude oil and natural gas production averaged 54,121 boe/d. Average production in the second quarter of 2026 increased 27% compared to the second quarter of 2025 average production of 42,542 boe/d, primarily driven by the closing of the Frontera Transaction on June 1, 2026. Refer to "Consolidated Results of Operations" for production split by product type.
- Recognized net income of $444.3 million ($4.62 per share basic) compared to net income of $49.1 million ($0.50 per share basic) in the second quarter of 2025. The increase was primarily attributed to the gain on acquisition, increased revenue resulting from higher volumes and crude oil prices, and a deferred tax recovery, partially offset by realized losses on commodity risk management contracts, one-time costs and higher current income tax.
- Generated quarterly adjusted funds flow provided by operations ("FFO")(1) of $191.2 million ($1.99 per share basic(2)) compared to $103.7 million ($1.06 per share basic(2)) in the second quarter of 2025. The increase is primarily attributed to the increase in realized price and volumes. Q2 2026 adjusted FFO(1) incorporates one-time costs of approximately $59.1 million comprised of: $28.4 million of nonrecurring transaction-related costs and $30.7 million of realized losses on hedging contracts.
- Generated an operating netback(2) of $45.14/boe (Q2 2025 - $36.25/boe) and an adjusted FFO netback(2) of $37.26/boe (Q2 2025 - $26.60/boe(2)) from an average Brent price of $96.68/bbl (Q2 2025 - $66.71/bbl).
- Incurred $133.7 million of capital expenditures(3) compared to $88.7 million in the second quarter of 2025. The increase is primarily related to activities at LLA-111, LLA-34, VIM-1, and Capachos.
- Paid a regular quarterly dividend of C$0.385 per share(4).
- Repaid $175.2 million of bank debt with the available capacity under the credit facility undrawn.

(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

The Company has reaffirmed its second half ("H2") of 2026 and full-year ("FY") 2026 guidance released on May 12, 2026, reflecting continued confidence in its operational outlook following the Frontera Transaction and the expected timing of production from the Magdalena assets.

Category	**H2 2026 Guidance** *(May 12, 2026)*(1)
Brent Crude Oil Average Price	$90/bbl
Average Production	82,000-91,000 boe/d
Funds Flow Provided by Operations Netback(2)	$30-33/boe
Funds Flow Provided by Operations(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 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, with capital expenditures of $495 to $515 million.

The Company continues to monitor market conditions that may influence operating costs and realized pricing. Currently, elevated energy costs, driven in part by El Niño-related weather impacts and broader market conditions, together with adverse foreign exchange movements resulting from Colombian peso appreciation, are contributing to production expenses trending to the upper end of guidance. Vasconia differentials also remain elevated, reflecting current market dynamics

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

Financial Summary

(Financial figures in $'000s except per share amounts)	For the three months ended June 30, **2026**	2025	For the six months ended June 30, **2026**	2025
Light Crude Oil and Medium Crude Oil (bbl/d)	**14,515**	10,182	**14,126**	10,229
Heavy Crude Oil (bbl/d)	**37,130**	31,047	**33,222**	31,623
Natural gas liquids (boe/d)	**765**	316	**508**	345
Average oil production (bbl/d)(1)	**52,410**	41,545	**47,856**	42,197
Average conventional natural gas production (mcf/d)(1)	**10,266**	5,982	**9,594**	5,400
Average oil and natural gas production (boe/d)	**54,121**	42,542	**49,455**	43,097
Production split (% crude oil)	**97**	98	**97**	98
Oil and natural gas sales price ($/boe)(6)	**90.84**	61.35	**80.67**	64.35
Operating netback ($/boe) (1)	**45.14**	36.25	**42.50**	37.84
Funds flow provided by operations netback ($/boe)(1)	**25.74**	26.90	**26.88**	28.91
Adjusted funds flow provided by operations netback ($/boe)(1)	**37.26**	26.60	**33.66**	28.94
Oil and natural gas sales	**466,016**	239,070	**737,393**	504,705
Funds flow provided by operations(7)	**132,054**	104,821	**245,756**	226,765
Per share – basic(1)(3)	**1.37**	1.08	**2.56**	2.32
Per share – diluted (1)(3)	**1.37**	1.08	**2.55**	2.32
Adjusted Funds flow provided by operations(7)	**191,155**	103,653	**307,703**	226,958
Per share – basic(1)(3)	**1.99**	1.06	**3.20**	2.32
Per share – diluted (1)(3)	**1.98**	1.06	**3.20**	2.32
Net income	**444,296**	49,113	**448,885**	129,742
Per share – basic(3)	**4.62**	0.50	**4.67**	1.33
Per share – diluted(3)	**4.61**	0.50	**4.66**	1.33
Dividends paid	**26,483**	27,561	**53,420**	53,926
Per share - Cdn$(3)(6)	**0.385**	0.385	**0.770**	0.770
Share repurchases	**—**	6,025	**—**	11,264
Number of shares repurchased (000s)	**—**	630	**—**	1,155
Capital expenditures(2)	**133,693**	88,690	**224,736**	145,744
Free funds flow(2)	**(1,639)**	16,131	**21,020**	81,021
EBITDA(2)	**487,551**	124,000	**583,381**	263,032
Adjusted EBITDA(2)	**192,063**	127,745	**324,747**	263,152
Total assets (end of period)	**4,235,530**	2,223,178	**4,235,530**	2,223,178
Net debt (net cash)(7)	**906,598**	(2,048)	**906,598**	(2,048)
Weighted average shares outstanding (000s)				
Basic	**96,179**	97,501	**96,086**	97,806
Diluted	**96,440**	97,501	**96,305**	97,806
Outstanding shares (end of period) (000s)	**96,180**	97,184	**96,180**	97,184

(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 June 30, 2026 and June 30, 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".

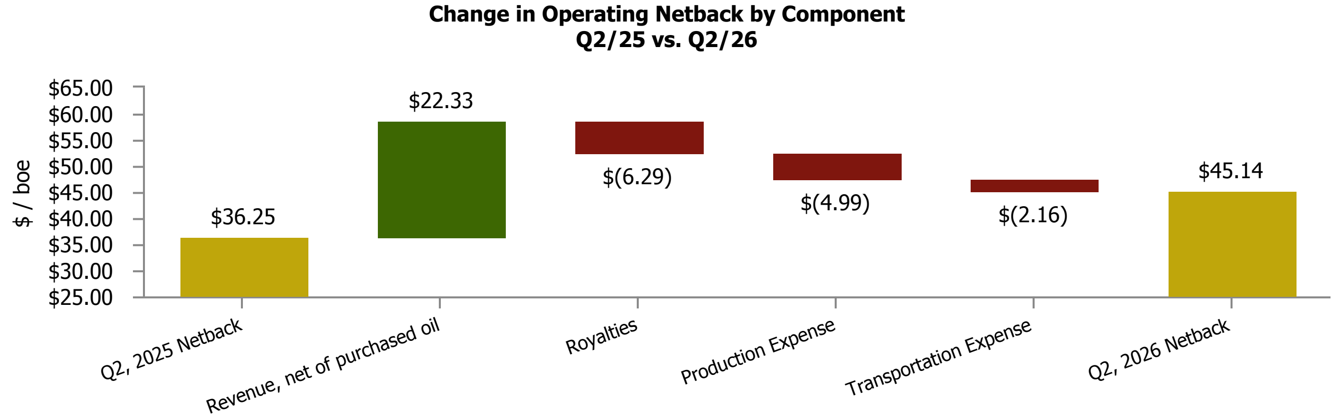
Financial and Operational Results

Consolidated Results of Operations

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

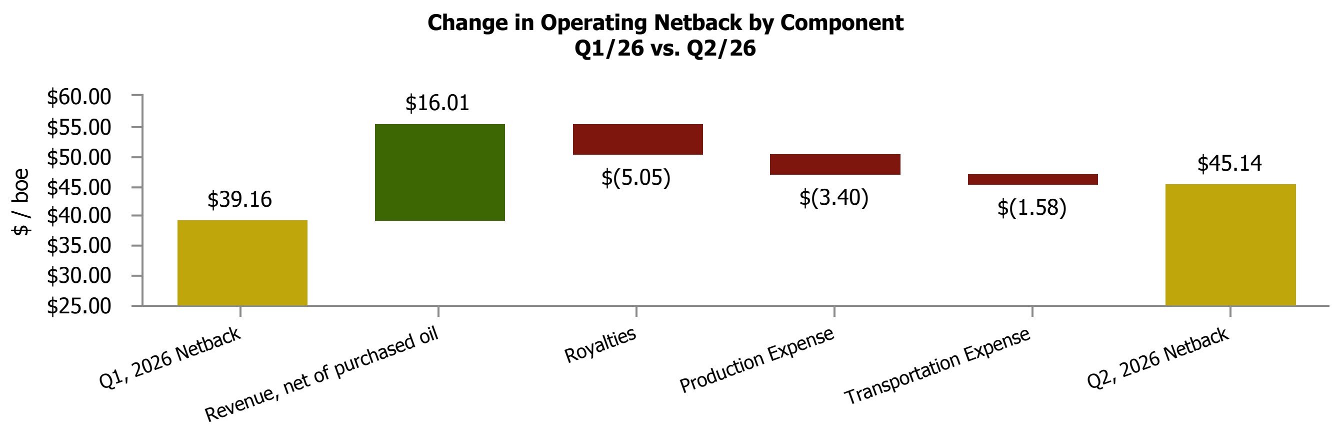
	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	**14,515**	10,182	**14,126**	10,229
Heavy Crude Oil (bbl/d)	**37,130**	31,047	**33,222**	31,623
Natural gas liquids (boe/d)	**765**	316	**508**	345
Crude Oil (bbl/d)	**52,410**	41,545	**47,856**	42,197
Conventional Natural Gas (mcf/d)	**10,266**	5,982	**9,594**	5,400
Total (boe/d)	**54,121**	42,542	**49,455**	43,097
Production split (% crude oil production)	**97**	98	**97**	98
Average daily sales of oil and natural gas				
Produced crude oil, before consumption (bbl/d)	**54,666**	41,828	**48,904**	42,435
Produced natural gas (mcf/d)	**10,266**	5,982	**9,594**	5,400
Produced crude oil and natural gas, before consumption (bbl/d)	**56,377**	42,825	**50,503**	43,335
Consumption for fuel	**(937)**	—	**(471)**	—
Produced oil and natural gas, after consumption	**55,440**	42,825	**50,032**	43,335
Purchased crude oil (bbl/d)	**3,191**	—	**1,604**	7
Total (boe/d)	**58,631**	42,825	**51,636**	43,342
Operating netback ($000s)				
Oil and natural gas sales	**$ 466,016**	$ 239,070	**$ 737,393**	$ 504,705
Purchased crude oil[4]	**(36,709)**	30	**(36,756)**	(162)
Oil and natural gas sales, net of purchased crude oil[2][4]	**429,307**	239,100	**700,637**	504,543
Royalties	**(72,961)**	(30,913)	**(109,749)**	(67,318)
Net revenue	**356,346**	208,187	**590,888**	437,225
Production expense	**(90,766)**	(49,492)	**(148,082)**	(106,350)
Transportation expense	**(34,019)**	(17,421)	**(54,276)**	(34,239)
Operating netback[1]	**$ 231,561**	$ 141,274	**$ 388,530**	$ 296,636
Operating netback (per boe)				
Brent ($/bbl)	**$ 96.68**	$ 66.71	**$ 87.60**	$ 70.81
Parex price differential	**(5.84)**	(5.36)	**(6.93)**	(6.46)
Oil and natural gas sales[2]	**90.84**	61.35	**80.67**	64.35
Purchased crude oil[2][4]	**(7.16)**	—	**(4.02)**	(0.01)
Oil and natural gas sales, net of purchased crude oil[2][4]	**83.68**	61.35	**76.65**	64.34
Royalties[2]	**(14.22)**	(7.93)	**(12.01)**	(8.58)
Net revenue[2]	**69.46**	53.42	**64.64**	55.76
Production expense[2]	**(17.69)**	(12.70)	**(16.20)**	(13.56)
Transportation expense[2]	**(6.63)**	(4.47)	**(5.94)**	(4.36)
Operating netback[3]	**$ 45.14**	$ 36.25	**$ 42.50**	$ 37.84

(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".
(4) Purchased crude oil cost includes ~$9.4 million of non-cash inventory fair value adjustment as a result of the purchase price allocation, equivalent to $1.83/boe and $1.02/boe for the three months and six months ended June 30, 2026, respectively.



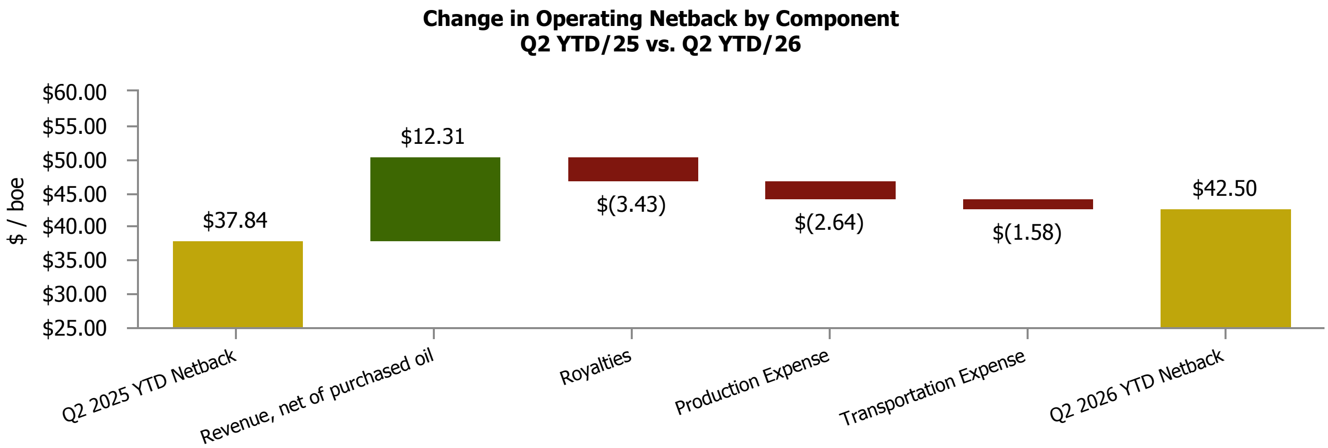
Overall, the Company's benchmark Brent crude oil price increased by $29.97/bbl, while revenue increased by $22.33/boe in the second quarter of 2026 as compared to the second quarter of 2025. The decrease in revenue relative to the Brent crude benchmark increase was primarily attributable to increased purchased crude oil for blending associated with newly acquired heavy oil volumes. Royalties increased by $6.29/boe in the quarter compared to the second quarter of 2025 primarily associated with the increase in sales price. Production expense in the quarter increased by $4.99/boe compared to the second quarter of 2025, including the impact of the of the Frontera Transaction, which contributed approximately $1.88/boe to the increase. The increase primarily reflected higher fuel-powered field operating costs due to higher crude oil prices, increased electrical power costs, higher fixed cost absorption and the appreciation of the COP. These factors were partially offset by reduced well workovers and facility maintenance costs. Transportation expense in the quarter increased by $2.16/boe compared to the second 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 increased by $8.89/boe compared to a Brent benchmark crude price increase of $29.97/bbl.



In the second quarter of 2026, the Company's benchmark Brent crude oil price increased by $18.30/bbl, while revenue increased by $16.01/boe as compared to the first quarter of 2026. The decrease in revenue relative to the Brent crude benchmark increase was primarily attributable to increased purchased oil for blending associated with newly acquired heavy oil volumes, partially offset by lower location and quality differentials and decreased wellhead sales. Royalties increased by $5.05/boe primarily associated with the increase in sales price. Production expense increased by $3.40/boe, including the impact of the of the Frontera Transaction, which contributed approximately $1.88/boe to the increase. The quarter-over-quarter increase primarily reflected higher fuel-powered field operating costs driven by higher crude oil prices, increased electrical power costs, higher fixed cost absorption and the appreciation of the COP. Transportation expense in the quarter increased by $1.58/boe compared to the first quarter of 2026 primarily due to an increase in the volume of oil production transported by truck and higher gas volumes transported.

Overall, the operating netback increased by $5.98/boe compared to a Brent benchmark crude price increase of $18.30/bbl.



Year to date 2026, the Company's benchmark Brent crude oil price increased by $16.79/bbl, while revenue increased by $12.31/boe as compared to the comparative 2025 period. The decrease in revenue relative to the Brent crude benchmark increase was primarily attributable to increased purchased oil for blending associated with newly acquired heavy oil volumes and increased location and quality differential, partially offset by decreased wellhead sales. Royalties increased by $3.43/boe primarily associated to the increase in sales price. Production expense increased by $2.64/boe, including the impact of the of the Frontera Transaction, which contributed approximately $1.18/boe to the increase. The increase primarily reflected higher fuel-powered field operating costs due to higher crude oil prices, increased electrical power costs, higher fixed cost absorption and the appreciation of the COP. These factors were partially offset by reduced well workovers and facility maintenance costs. Transportation expense in the quarter increased by $1.58/boe compared to the comparative 2025 period primarily due to an increase in the volume of oil production transported by truck and higher gas volumes transported.

Overall, the operating netback increased by $4.66/boe compared to a Brent benchmark crude price increase of $16.79/bbl.

Oil and Natural Gas Sales and Other Revenue

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

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Llanos	**30,568**	18,691	**26,474**	18,911
LLA-34	**19,183**	21,514	**19,206**	21,860
Magdalena	**3,605**	2,337	**3,104**	2,326
Putumayo	**765**	—	**671**	—
Total Crude oil and natural gas production	**54,121**	42,542	**49,455**	43,097
Crude oil inventory draw (build)	**2,256**	283	**1,048**	238
Average daily sales of produced oil and natural gas, before consumption	**56,377**	42,825	**50,503**	43,335
Consumption for fuel	**(937)**	—	**(471)**	—
Average daily sales of produced oil and natural gas, after consumption	**55,440**	42,825	**50,032**	43,335
Purchased oil	**3,191**	—	**1,604**	7
Sales Volumes	**58,631**	42,825	**51,636**	43,342

On June 1, 2026, the Company successfully closed its previously announced acquisition of Frontera Energy Corporation's Colombian exploration and production assets. The Company's production profile has experienced a step-change following the recently announced transactions, with additional growth opportunities expected as the expanded portfolio is further integrated and developed.

For the period of July 1, 2026, to July 29, 2026, estimated average production was 83,500 boe/d[(1)], demonstrating positive operational momentum.

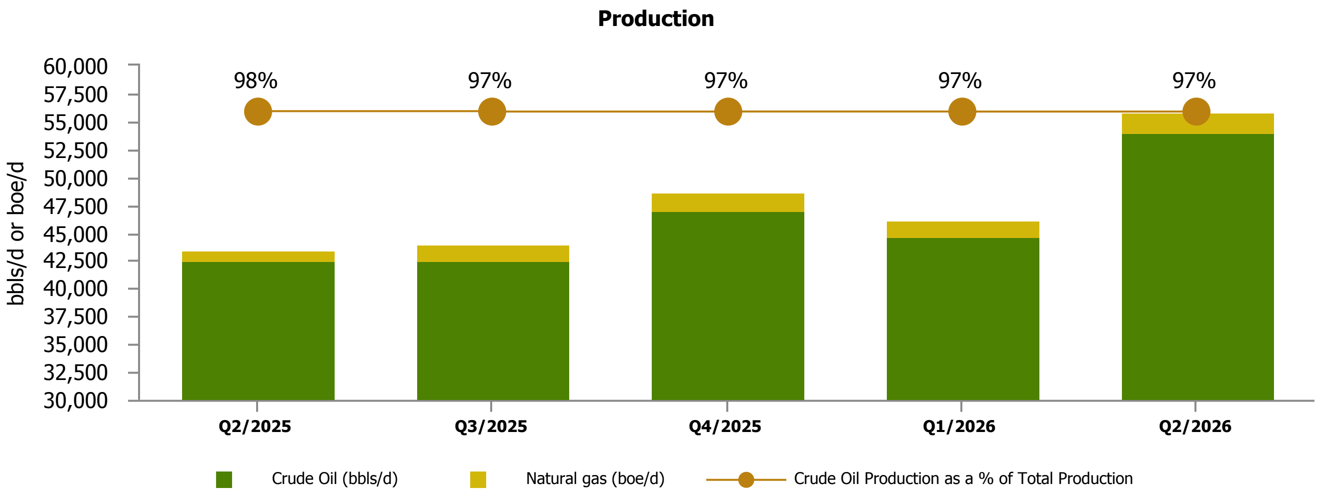
Crude oil and natural gas production for the second quarter of 2026 averaged 54,121 boe/d after reflecting the closing of the Frontera Transaction on June 1, 2026 and new production from exploration success on Block LLA-111. This is an increase of approximately 27% from the second quarter of 2025 production of 42,542 boe/d and an increase of approximately 21% compared to the first quarter of 2026 production of 44,735 boe/d. Refer to "Summary of Quarterly Results" for production split by product type.

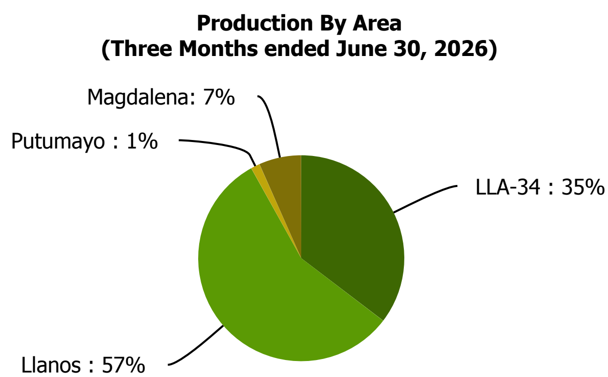
The increase in oil and natural gas production in the second quarter of 2026 compared to the second quarter of 2025 is mainly the result of production added from the closing of the Frontera Transaction on June 1, 2026, newly added production from Block LLA-74, LLA-111 and LLA-32 in the Llanos Basin and 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 increase in crude oil and natural gas production in the second quarter of 2026 compared to the first quarter of 2026 was mainly attributed to production added from the closing of the Frontera Transaction on June 1, 2026 and newly added production from Block LLA-111.

Oil and natural gas sales in the second quarter of 2026 were 58,631 boe/d compared to 42,825 boe/d for the second quarter of 2025, with the step change primarily driven by the closing of the Frontera Transaction on June 1, 2026 and new production from Block LLA-74, LLA-111 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.

(1) Estimated average production; light & medium crude oil: ~22,071 bbl/d, heavy crude oil: ~58,409 bbl/d, conventional natural gas: ~16,424 mcf/d, natural gas liquids: 333 boe/d; rounded for presentation purposes.





b) Crude Oil Reference and Realized Prices

Average price for the period	**Q2 2026**	Q1 2026	Q4 2025	Q3 2025	Q2 2025
Brent ($/bbl)	**96.68**	78.38	63.08	68.17	66.71
Parex location and quality differential ($/bbl)	**(2.88)**	(5.52)	(3.03)	(1.94)	(1.87)
Parex wellhead sales discount ($/bbl)	**(2.32)**	(5.16)	(3.35)	(3.91)	(3.77)
Parex realized oil sales price ($/bbl)(2)	**91.48**	67.70	56.70	62.32	61.07
Parex realized price (differential) to Brent $/bbl)	**(5.20)**	(10.68)	(6.38)	(5.85)	(5.64)
Parex transportation expense ($/bbl)(1)(2)	**(6.40)**	(5.10)	(5.47)	(4.88)	(4.58)
Parex price differential and transportation expense ($/bbl)(2)	**(11.60)**	(15.78)	(11.85)	(10.73)	(10.22)

(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 second quarter of 2026, benchmark Brent oil reference price increased by $18.30/bbl compared to the first quarter of 2026. The increase occurred amid continued geopolitical developments, including the continued outbreak of war in the Middle East, which disrupted regional crude oil production and transportation and heightened concerns regarding global crude oil supply. Crude oil prices were highly volatile in the latter part of the first quarter of 2026 and majority of the second quarter of 2026 as market participants reassessed expectations regarding the magnitude and duration of the supply disruption. Prices began to decline towards the latter part of June 2026.

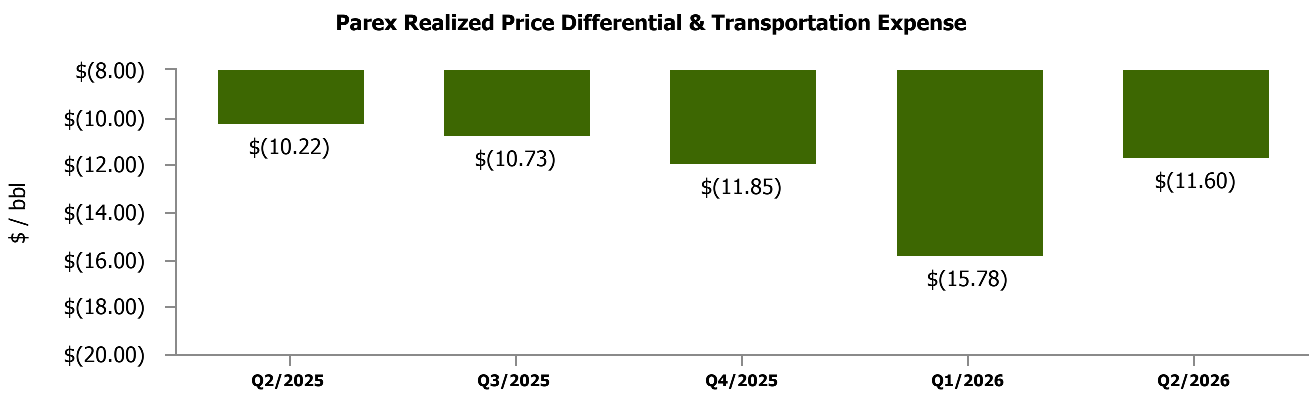
During the second quarter of 2026 the differential between Brent reference pricing and the Company's realized oil sale price was $5.20/bbl. The differential to Brent crude during the second quarter of 2026 decreased by $5.48/bbl compared to the first quarter of 2026 where the differential was $10.68/bbl primarily due to narrower location and quality differentials. This improvement reflected the easing of macroeconomic volatility and expectations of incremental heavy oil supply that had widened differentials during the first quarter of 2026, as well as a reduction in wellhead sales in favour of higher-priced direct export sales. Compared to the second quarter of 2025 Parex's realized oil price differential decreased from $5.64/bbl to $5.20/bbl, which was primarily driven by reduced wellhead sales in favour of direct export sales, partially offset by increased location and quality differentials on heavy oil associated with newly acquired volumes.

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 second quarter 2026 location and quality differential of $2.88/bbl increased compared to the second quarter of 2025 of $1.87/bbl. These differentials continue to reflect current global commodity market dynamics, including heavy oil supply and demand fundamentals as well as overall market conditions.

The Vasconia differential to Brent can fluctuate with oil market conditions and for the month of July 2026 was approximately $7.00/bbl.



c) Natural Gas Sales and Realized Prices

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Natural gas sales ($000’s)	**$ 10,940**	$ 6,605	**$ 19,863**	$ 12,363
Realized sales price ($/Mcf)(1)	**11.71**	12.13	**11.44**	12.65

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

Parex's natural gas sales were $10.9 million and $19.9 million for the three and six months ended June 30, 2026 compared to $6.6 million and $12.4 million in the comparative periods of 2025. The increase in natural gas sales from the comparative periods of 2025 is primarily related to increased volumes sold from the Capachos and VIM-1 Blocks and the closing of the Frontera Transaction on June 1, 2026, partially offset by a decrease in realized gas sales price.

d) Oil and Natural Gas Sales

Second quarter 2026 oil and natural gas sales increased by $226.9 million or 95% as reconciled in the table below to the second quarter of 2025:

($000s)		
Oil and natural gas sales, three months ended June 30, 2025	**$**	**239,070**
Sales volume of produced oil, an increase of 28% (11,901 bopd)		**66,138**
Sales volume of purchased oil, an increase of 100% (3,191 bopd)		**17,734**
Oil sales price increase		**138,739**
Sales volume and price change of produced natural gas		**4,335**
Oil and natural gas sales, three months ended June 30, 2026	**$**	**466,016**

Oil and natural gas sales increased in the three months ended June 30, 2026 compared to the same period in 2025 mainly due to the increase in world oil prices in addition to higher sales volumes as result of production added from the closing of the Frontera Transaction on June 1, 2026 and newly added production from Block LLA-74, LLA-111 and LLA-32 in the Llanos Basin.

e) Crude Oil Inventory

As at June 30, ($000s)		**2026**		2025
Crude oil in transit	**$**	**26,220**	$	209

At June 30, 2026, the Company had 488.7 mbbls of crude oil inventory compared to 5.5 mbbls at June 30, 2025, which was injected into Colombian pipelines and stored in tanks. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at $53.65/bbl at June 30, 2026 compared to $38.00/bbl at June 30, 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)	**Jun. 30, 2026**	Mar. 31, 2026	Dec. 31, 2025	Sep. 30, 2025
Crude oil inventory - beginning of the period	**132.5**	116.9	4.9	5.5
Crude oil inventory - acquired on acquisition	**706.3**	—	—	—
Oil production	**4,769.3**	3,892.4	4,333.4	3,914.7
Oil sales	**(5,265.0)**	(3,876.8)	(4,221.4)	(3,915.3)
Consumption for fuel	**(85.3)**	—	—	—
Purchased oil	**230.9**	—	—	—
Crude oil - end of the period	**488.7**	132.5	116.9	4.9
% of period production	**10.2**	3.4	2.7	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.

f) Purchased Oil

	For the three months ended June 30,				For the six months ended June 30,			
		2026		2025		**2026**		2025
Purchased oil expense ($000s)	**$**	**36,709**	$	(30)	**$**	**36,756**	$	162

Purchased oil expense has increased for the three and six months ended June 30, 2026 compared to the same periods in 2025 primarily due to higher oil blending activity associated with the Frontera acquired assets.

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 June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Other revenue	**$ 2,909**	$ 2,319	**$ 4,664**	$ 4,831

Royalties

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Base royalties[1]	**$ 43,179**	$ 19,082	**$ 64,484**	$ 40,629
Economic rights[2]	**29,782**	11,831	**45,265**	26,689
Royalties ($000s)	**$ 72,961**	$ 30,913	**$ 109,749**	$ 67,318
Per unit ($/boe)[3]	**14.22**	7.93	**12.01**	8.58
Percentage of sales[3]	**17**	13	**15**	13

(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".

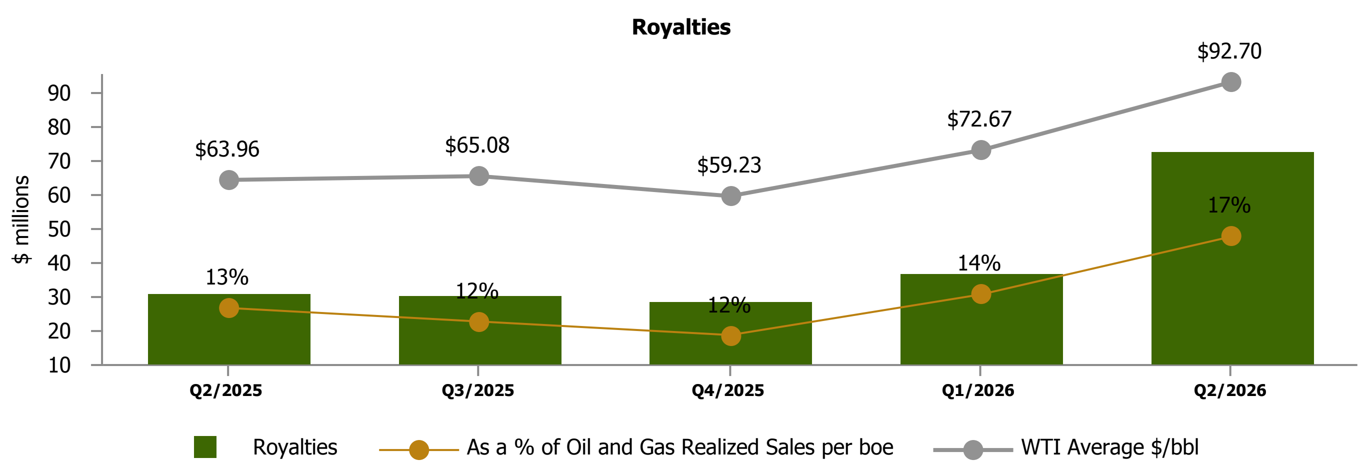
Royalty expense was $73.0 million and $109.7 million for the three and six months ended June 30, 2026 compared to $30.9 million and $67.3 million for the 2025 comparative period.

Royalties as a percentage of sales were 17% and 15% for the three and six months ended June 30, 2026 compared to 13% for the 2025 comparative periods.

The increase in royalty expense was primarily attributable to the increase in world oil prices in 2026 and base production, 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 and six months ended June 30, 2026 were $92.70 and $82.77 compared to $63.96 and $67.73 for the 2025 comparative period and $72.67 in the first quarter of 2026.

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 June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Production expense ($000s)	**$ 90,766**	$ 49,492	**$ 148,082**	$ 106,350
Per unit ($/boe)(1)	**17.69**	12.70	**16.20**	13.56

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

Production expense for the three and six months ended June 30, 2026 was $17.69/boe and $16.20/boe compared to $12.70/boe and $13.56/boe for the three and six months ended June 30, 2025. Production expense for the first quarter of 2026 was $14.29/boe.

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

	Q2 2026 vs Q1 2026	**Q2 2026 vs Q2 2025**	**YTD 2026 vs YTD 2025**
Comparative period production expense per boe(1)	**$ 14.29**	**$ 12.70**	**$ 13.56**
Power generation	**1.22**	**2.30**	**0.81**
Well workovers and facility maintenance	**0.04**	**(1.13)**	**(0.35)**
Colombian pesos ("COP") appreciation	**0.23**	**1.38**	**1.50**
Fixed costs absorption	**2.30**	**2.12**	**0.32**
Other variable costs	**(0.39)**	**0.32**	**0.36**
Current period production expense per boe(1)	**$ 17.69**	**$ 17.69**	**$ 16.20**

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

Production expense per boe increased for the three months ended June 30, 2026 compared with the same period in 2025, including the impact of the of the Frontera Transaction, which contributed approximately $1.88/boe. The increase primarily reflected higher fuel-powered field operating costs due to higher crude oil prices, increased electrical power costs, higher fixed cost absorption and the appreciation of the COP. These factors were partially offset by reduced well workovers and facility maintenance costs.

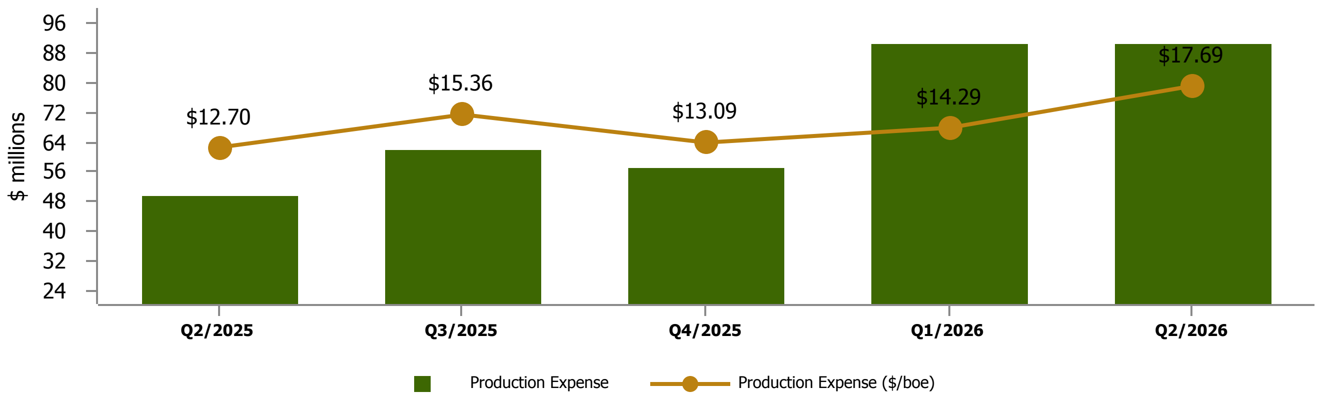
Production expense per boe increased for the six months ended June 30, 2026 compared with the same period in 2025, including the impact of the of the Frontera Transaction, which contributed approximately $1.18/boe. The increase primarily reflected higher fuel-powered field operating costs due to higher crude oil prices, increased electrical power costs, higher fixed cost absorption and the appreciation of the COP. These factors were partially offset by reduced well workovers and facility maintenance costs.

Production expense per boe increased in the second quarter of 2026 compared with the first quarter of 2026, including the impact of the of the Frontera Transaction. The quarter-over-quarter increase primarily reflected higher fuel-powered field operating costs driven by higher crude oil prices, increased electrical power costs, higher fixed cost absorption and the appreciation of the COP.

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. Elevated energy costs, influenced in part by El Niño-related weather impacts and broader market conditions, are contributing to higher operating cost expectations. Fuel power costs have increased consistent with the increase experienced in world oil prices.

The Company continues to monitor market conditions that may influence operating costs and realized pricing. Assuming current conditions persist, the Company expects production expense to trend toward the upper end of the guidance range of $16-20/boe for H2 2026, after accounting for the Frontera Transaction, and the addition of the new producing assets in the Magdalena Basin.

Production Expense



Transportation Expense

	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
Transportation expense ($000s)	**$ 34,019**	$ 17,421	**$ 54,276**	$ 34,239
Per unit ($/boe)[1]	**6.63**	4.47	**5.94**	4.36

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

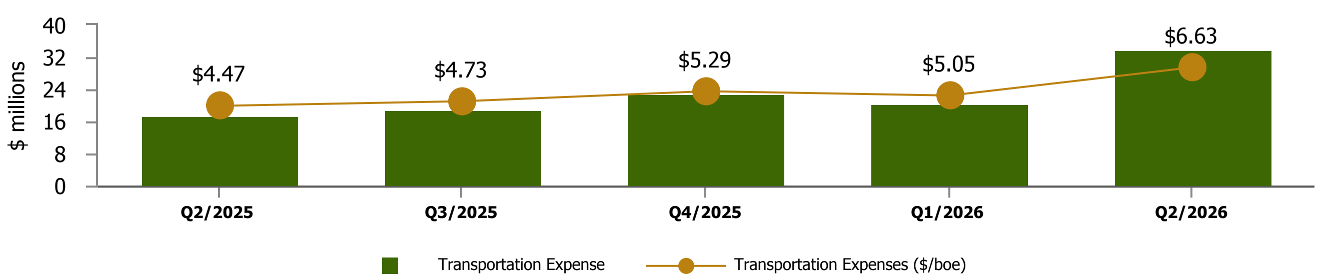
Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility and pipeline tariffs.

For the three and six months ended June 30, 2026 the cost of transportation on a per boe basis was $6.63/boe and $5.94/boe compared to $4.47/boe and $4.36/boe for the three and six months ended June 30, 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 production added from the closing of the Frontera Transaction on June 1, 2026, and additional production from Azogue on Block LLA-32 and new production from Blocks LLA-74 and LLA-111. Transportation expense will fluctuate period over period due the mix of sales contracts types in force during the period.

The Company expects transportation expense guidance to be approximately $7.50/bbl for H2 2026, after accounting for the Frontera Transaction, and the addition of the new producing assets in the Magdalena Basin.

The combined transportation expense and price differential from Brent, on a per boe basis, has increased from the second quarter of 2025 and decreased from the first quarter of 2026. See "Crude Oil Reference and Realized Prices".

Transportation Expense



General and Administrative Expense ("G&A")

($000s)	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Gross G&A	**$ 27,512**	$ 20,137	**$ 54,742**	$ 41,723
G&A recoveries	**(1,693)**	(1,140)	**(4,113)**	(2,476)
Capitalized G&A	**(2,407)**	(2,313)	**(4,790)**	(4,792)
Total net G&A	**$ 23,412**	$ 16,684	**$ 45,839**	$ 34,455
Per unit ($/boe) (1)	**4.75**	4.31	**5.12**	4.42

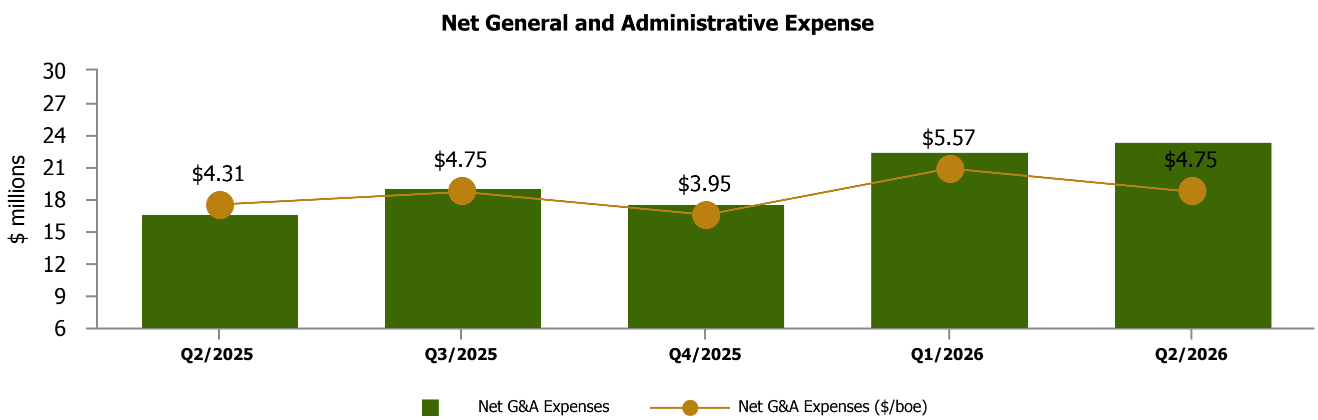
(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Net G&A was $23.4 million and $45.8 million for the three and six months ended June 30, 2026 compared to $16.7 million and $34.5 million for the three and six months ended June 30, 2025. Gross G&A was $27.5 million and $54.7 million for the three and six months ended June 30, 2026 (three and six months ended June 30, 2025 - $20.1 million and $41.7 million). Gross and net G&A have increased compared 2025 as a result of one time severance costs of $2.3 million, increased staffing levels compared to the prior periods, both pre and post acquisition of Frontera, and the appreciation of the Canadian dollar ("Cdn") and COP.

On a per boe basis, net G&A for the six months ended June 30, 2026 increased 16% to $5.12 from $4.42 in the comparative period of 2025 as a result of the increases noted above.

The Company expects G&A expense guidance to be approximately $5.00/bbl for H2 2026, after accounting for the Frontera Transaction, and the addition of the new producing assets in the Magdalena Basin.

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

($000s)	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Equity settled share-based compensation expense	**$ 265**	$ 182	**$ 439**	$ 362
Cash settled share-based compensation expense (recovery)	**(606)**	6,294	**17,887**	8,206
Total share-based compensation expense (recovery)	**$ (341)**	$ 6,476	**$ 18,326**	$ 8,568

Share-based compensation was a recovery of $0.3 million and expense of $18.3 million for the three and six months ended June 30, 2026 compared to an expense of $6.5 million and $8.6 million for the three and six months ended June 30, 2025.

Equity settled share-based compensation expense was $0.3 million and $0.4 million for the three and six months ended 2026 compared to $0.2 million and $0.4 million for the three and six months ended June 30, 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 for the three and six months ended June 30, 2026 was a recovery of $0.6 million and an expense $17.9 million compared to $6.3 million and $8.2 million expense for the same period in 2025. The increase in expense for the six months ended June 30, 2026 is mainly attributable to additional units issued and the increase in share price. Parex's share price increased 16% during the first half of 2026. The lower expense for the six months ended June 30, 2025 is mainly attributable to the 5% 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 17 - Cash Settled Incentive Plans of the interim consolidated financial statements for the six months ended June 30, 2026. As at June 30, 2026, the total cash settled incentive plans liability accrued was $27.1 million (December 31, 2025 - $37.6 million).

Cash payments to settle cash settled share-based compensation in the three and six months ended June 30, 2026 were $3.4 million and $29.6 million compared to $0.5 million and $11.2 million for the same periods in 2025. The increase in the six months ended June 30, 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")

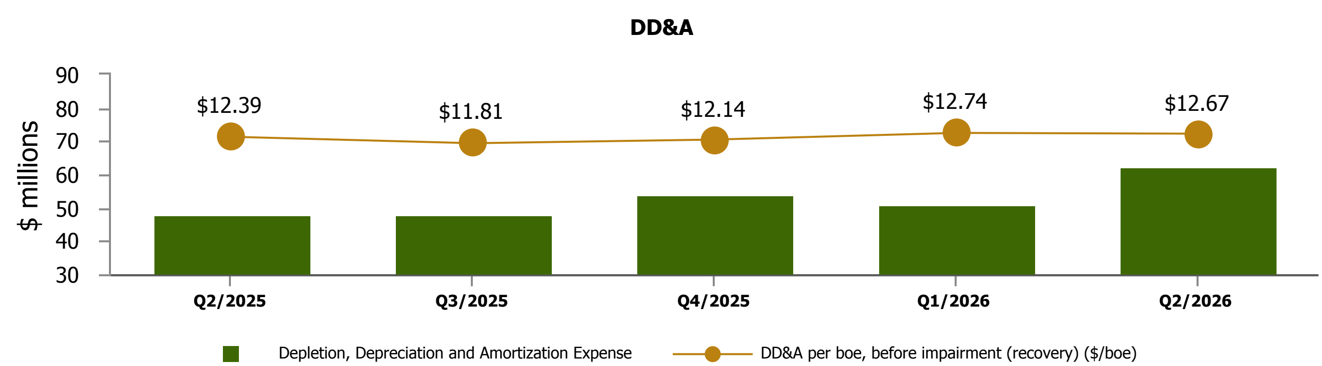
	For the three months ended June 30,		For the six months ended June 30,	
	2026	2025	**2026**	2025
DD&A expense ($000s)	**$ 62,382**	$ 47,949	**$ 113,671**	$ 98,368
Per unit ($/boe)(1)	**12.67**	12.39	**12.70**	12.61

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

Second quarter 2026 DD&A was $62.4 million ($12.67/boe) compared to $47.9 million ($12.39/boe) for the same period in 2025.

For the six months ended June 30, 2026 future development costs of $836.0 million (six months ended June 30, 2025 - $378.0 million) were included in the depletion calculation.

Second quarter 2026 DD&A of $12.67/boe has increased from the comparative period in 2025 of $12.39/boe and decreased slightly from the first quarter of 2026 of $12.74/boe due the increase in depletable base as result of the closing of the Frontera Transaction, transfer of Block LLA-111 costs from E&E and higher production.



Foreign Exchange

($000s)		For the three months ended June 30, 2026		2025		For the six months ended June 30, 2026		2025
Foreign exchange loss	**$**	**1,128**	$	3,320	**$**	**3,403**	$	1,736
Foreign currency risk management contracts gain		**(5,696)**		(5,357)		**(5,884)**		(5,357)
Total foreign exchange gain	**$**	**(4,568)**	$	(2,037)	**$**	**(2,481)**	$	(3,621)
Average foreign exchange rates								
USD$/Cdn$		**1.37**		1.38		**1.38**		1.41
USD$/COP		**3,612**		4,199		**3,656**		4,196

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 net income and 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 and six months ended June 30, 2026, the Company recognized total net foreign exchange gains, including the impact of hedging, of $4.6 million and $2.5 million, respectively, compared with net foreign exchange gains of $2.0 million and $3.6 million for the three and six months ended June 30, 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 net income and comprehensive income.

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

Foreign Exchange Sensitivity Analysis

		$/boe Impact of change in local currency/$USD exchange rate			
Cost component	Estimated percent of cost denominated in local currency		10% appreciation of local currency		10% depreciation of local currency
Production expense	90%	$	1.59	$	(1.59)
Transportation expense	50%	$	0.33	$	(0.33)
G&A expense	100%	$	0.48	$	(0.48)

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 Q2 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 June 30, 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 $19.9 million.

Other Expense

($000s)	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Other Colombian taxes	**$ 622**	$ 2,545	**$ 2,203**	$ 3,326
Colombian tax credit purchased	**—**	8,097	**—**	8,097
Equity tax	**(712)**	—	**6,288**	—
Legal provisions	**1,343**	—	**1,519**	—
(Gain) loss on settlement of decommissioning liabilities	**(1,205)**	357	**(1,221)**	545
Loss on disposition of tangible assets	**4,232**	17	**4,371**	35
Site restoration costs	**4,234**	—	**10,803**	—
Other	**456**	1,437	**2,364**	1,597
Total other expense	**$ 8,970**	$ 12,453	**$ 26,327**	$ 13,600

($000s)	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Non-cash other expense	**$ 4,955**	$ 374	**$ 5,254**	$ 580
Cash other expense	**4,015**	12,079	**21,073**	13,020
Total other expense	**$ 8,970**	$ 12,453	**$ 26,327**	$ 13,600

Other expense is comprised mainly of other Colombian taxes including the 1% surcharge on the sale or export of crude oil effective for 2025, equity tax, legal provisions, Colombian tax credit purchased to reduce income tax expense in 2025, (gain) loss on settlement of decommissioning liabilities, loss on disposition of tangible assets, site restoration costs 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 payable was settled by June 30, 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

($000s)	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Bank charges and credit facility fees	**$ 1,008**	$ 1,402	**$ 2,226**	$ 2,191
Interest on bank debt	**3,052**	465	**4,826**	1,234
Interest on senior unsecured notes	**7,853**	—	**7,853**	—
Amortization of deferred financing charges	**333**	—	**333**	—
Accretion on decommissioning and environmental liabilities	**3,624**	3,316	**6,268**	6,538
Interest and other income	**(2,740)**	(612)	**(6,144)**	(1,909)
Lease obligation interest expense	**268**	46	**447**	93
Expected credit loss provision (recovery)	**139**	(50)	**613**	(149)
Other	**942**	295	**1,418**	623
Net finance expense	**$ 14,479**	$ 4,862	**$ 17,840**	$ 8,621

($000s)	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Non-cash finance expense	**$ 3,764**	$ 3,262	**$ 6,882**	$ 6,386
Cash finance expense	**10,715**	1,600	**10,958**	2,235
Net finance expense	**$ 14,479**	$ 4,862	**$ 17,840**	$ 8,621

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 June 30, 2026, the Company had no crude oil risk management contracts in place. The Company is currently unhedged for the remainder of 2026, with full exposure to changes in commodity prices.

The table below summarizes the loss (gain) on the commodity risk management contracts that were in place during the three and six months ended June 30, 2026 and 2025:

	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Realized loss (gain) on commodity risk management contracts	**$ 30,711**	$ (3,337)	**$ 32,947**	$ (3,337)
Premiums paid on commodity risk management contracts	**—**	2,169	**—**	3,530
Unrealized gain on commodity risk management contracts	**(30,635)**	(362)	**(1,050)**	(1,160)
Total loss (gain)	**$ 76**	$ (1,530)	**$ 31,897**	$ (967)

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 June 30, 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
June 19, 2026 to December 15, 2026	COP	Costless collar	$90,000,000	3,400-3,663	N/A

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three and six months ended June 30, 2026 and 2025 which is recorded in the financial statement line item "Foreign exchange gain" in the consolidated statements of net income and comprehensive income:

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2026**	2025	**2026**	2025
Realized gain on foreign currency risk management contracts	**$ (1,670)**	$ (1,225)	**$ (1,777)**	$ (1,225)
Unrealized gain on foreign currency risk management contracts	**(4,026)**	(4,132)	**(4,107)**	(4,132)
Total	**$ (5,696)**	$ (5,357)	**$ (5,884)**	$ (5,357)

Marketable Securities

	June 30, 2026	December 31, 2025
Marketable securities	**$ 55,375**	$ 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 June 30, 2026 was $55.4 million, resulting in an unrealized gain of $10.3 million, which is recorded in the consolidated statement of net income and 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

($000s)	For the three months ended June 30, 2026	2025	For the six months ended June 30, 2026	2025
Current tax expense	**$ 16,889**	$ 9,245	**$ 17,960**	$ 21,132
Deferred tax (recovery) expense	**(59,465)**	378	**(41,302)**	(8,431)
Tax (recovery) expense	**$ (42,576)**	$ 9,623	**$ (23,342)**	$ 12,701
Effective current tax rate on funds flow provided by operations before tax(1)	**11 %**	8 %	**7 %**	9 %

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

Current tax expense for the three months ended June 30, 2026 was $16.9 million compared to $9.2 million in the three months ended June 30, 2025.

The decrease in current tax expense for the six months ended June 30, 2026 compared to the 2025 comparative period is the result of the continued availability of tax pools in Colombia.

Deferred tax recovery for the three and six months ended June 30, 2026 was $59.5 million and $41.3 million compared to an expense of $0.4 million in the three months ended June 30, 2025 and recovery of $8.4 million for the six months ended June 30, 2025.

The increase in deferred tax recovery for the three and six months ended June 30, 2026 was primarily due to higher tax values than book values for PPE and tax loss carry-forwards associated with the Frontera Transaction. The appreciation of COP also contributed to the increase in the deferred tax recovery.

2026 Current Tax Guidance

The Company expects the effective current tax rate on funds flow provided by operations before tax guidance to be approximately 12-15% for H2 2026, after accounting for the Frontera Transaction, and the addition of new producing assets in the Magdalena Basin.

The table below reflects the Company's expected effective current tax rate on funds flow provided by operations before tax in 2026 after accounting for the Frontera Transaction, and the addition of the new producing assets in the Magdalena Basin:

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 June 30,	Colombia		Canada		Total	
($000s)	**2026**	2025	**2026**	2025	**2026**	2025
Acquisition of unproved properties	**$ 4,408**	$ 616	**$ —**	$ —	**$ 4,408**	$ 616
Geological and geophysical	**835**	8,699	**—**	—	**835**	8,699
Drilling and completion	**111,687**	68,754	**—**	—	**111,687**	68,754
Well equipment and facilities	**15,015**	10,492	**—**	—	**15,015**	10,492
Other	**1,528**	—	**220**	129	**1,748**	129
Total capital expenditures(1)	**$ 133,473**	$ 88,561	**$ 220**	$ 129	**$ 133,693**	$ 88,690

For the six months ended June 30,	Colombia		Canada		Total	
($000s)	**2026**	2025	**2026**	2025	**2026**	2025
Acquisition of unproved properties	**$ 4,408**	$ 1,226	**$ —**	$ —	**$ 4,408**	$ 1,226
Geological and geophysical	**835**	8,965	**—**	—	**835**	8,965
Drilling and completion	**194,892**	122,109	**—**	—	**194,892**	122,109
Well equipment and facilities	**22,654**	13,220	**—**	—	**22,654**	13,220
Other	**1,536**	—	**411**	224	**1,947**	224
Total capital expenditures(1)	**$ 224,325**	$ 145,520	**$ 411**	$ 224	**$ 224,736**	$ 145,744

(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:

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2026**	2025	**2026**	2025
Llanos Basin	**$ 77,130**	$ 68,413	**$ 122,697**	$ 112,199
Putumayo Basin	**16,910**	2,389	**48,139**	2,389
Block LLA-34	**19,924**	$ 15,908	**30,117**	28,343
Magdalena Basin	**18,491**	1,851	**22,346**	2,589
Canada and Colombia - Corporate	**1,238**	129	**1,437**	224
Total capital expenditures(1)	**$ 133,693**	$ 88,690	**$ 224,736**	$ 145,744

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

During the six months ended June 30, 2026 the Company incurred $224.7 million of capital expenditures with 97% spent on drilling, completion, well equipment and facilities in Colombia. During the six months ended June 30, 2025, the Company incurred $145.7 million of capital expenditures with 93% spent on drilling, completion, well equipment and facilities in Colombia.

During the second quarter of 2026 the Company incurred $133.7 million of capital expenditures with 95% spent on drilling, completion, well equipment and facilities in Colombia. During the second quarter of 2025, the Company incurred $88.7 million of capital expenditures with 89% spent on drilling, completion, well equipment and facilities in Colombia.

During the six months ended June 30, 2026 the Company's capital expenditures of $224.7 million were self-funded from funds flow provided by operations of $245.8 million.

Business Combination

Frontera Transaction

On June 1, 2026, the Company closed its previously announced acquisition of all the Colombian exploration and production assets of Frontera Energy Corporation, pursuant to which the Company, through a wholly-owned subsidiary, acquired 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 cash consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million (the "Frontera Transaction"). The Frontera Transaction was funded with the proceeds from the Company's issuance of senior unsecured notes, see Note 14 - Debt for details.

The contingent consideration is payable to Frontera if, within 12 months following the closing of the Frontera Transaction, the Company obtains a contractual amendment or other binding agreement extending the term of the Quifa Association Contract. At the acquisition date, the contingent consideration was recognized at its estimated fair value of $12.5 million, reflecting management's probability-weighted assessment of the payment condition being satisfied. As any payment, if triggered, is expected within 12 months of the acquisition date, the effect of discounting was not material.

The fair value measurement of the contingent consideration is classified within Level 3 of the fair value hierarchy because it uses significant unobservable inputs, principally the probability of obtaining the required contractual extension. The contingent consideration was remeasured at June 30, 2026, with no change in its fair value recognized during the period.

IFRS 3 requires the amounts to record for the underlying assets and liabilities acquired to be determined at the closing date (the "acquisition date") whereas the consideration for the business was negotiated earlier and voted on by the Frontera shareholders April 30, 2026. Furthermore, deferred tax assets are recorded at undiscounted amounts based on temporary differences existing at the acquisition date and are therefore not recorded at fair value under IFRS. The tax basis of the underlying assets acquired is in Colombian pesos which differs from the functional currency of the company and due to volatility in currencies this also significantly increased the US dollar equivalent value of the tax pools at the acquisition date relative to the time when the purchase was negotiated. As a result, the Company has estimated that the deferred tax assets contributed to the recognition of a bargain purchase gain approximating the deferred tax assets recognized.

The consolidated statements of net income and comprehensive income include results of operations of the Frontera Transaction since the closing date of June 1, 2026. The Company incurred transaction costs in connection with the Frontera Transaction of $28.4 million and $29.0 million for the three and six months ended June 30, 2026 respectively, which are expensed as incurred and presented in the consolidated statements of net income and comprehensive income.

The below amounts are estimates which were made by management at the time of the preparation of these condensed interim consolidated financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized for a period of up to one year. The pro forma information disclosed below is presented for informational purposes only and is not necessarily indicative of the results that would have been achieved had the Frontera Transaction occurred on January 1, 2026, nor is it indicative of future results.

The key assumptions used in the business combination to calculate the purchase price allocation include reserve estimates of proved plus probable reserves acquired that are based on production forecasts, future commodity prices, future development costs and future production costs.

As a result of the acquisition, the Company recognized a bargain purchase gain of $302.5 million, representing the excess of the fair value of the identifiable net assets acquired over the consideration transferred. The bargain purchase gain was recognized in the consolidated statements of net income and comprehensive income.

Before recognizing the bargain purchase gain, the Company assessed the completeness and accuracy of the assets acquired, liabilities assumed and consideration transferred, including the valuation methodologies and key assumptions applied in determining acquisition-date fair values, in accordance with IFRS 3.

Assets acquired and liabilities assumed

Assets		
Cash and cash equivalents	$	165,859
Restricted cash and cash equivalents		10,657
Accounts receivables		84,094
Prepaids and other current assets		11,181
Short-term inventory		67,569
Current income tax receivable		61,927
Exploration and evaluation assets		11,089
Property, plant and equipment		986,557
Right-of-use-asset		16,003
Other long-term assets		18,198
Deferred tax asset		302,483
Liabilities		
Accounts payable and accrued liabilities		(344,031)
Derivative financial instruments		(1,282)
Long-term debt - unsecured notes		(307,311)
Customer prepayments		(80,300)
Lease obligations		(16,003)
Decommissioning and environmental liabilities		(179,999)
Other long-term liabilities		(8,013)
Net assets acquired	**$**	**798,678**
Consideration transferred		(496,195)
Bargain purchase gain	**$**	**302,483**

Consideration for the acquisition		
Base purchase price	$	500,000
Purchase price adjustments		(16,305)
Cash consideration paid at closing		483,695
Fair value of contingent consideration		12,500
Total consideration	**$**	**496,195**

Cash paid	$	483,695
Less: Cash and cash equivalents acquired		(176,516)
Net cash outflow on acquisition	**$**	**307,179**

The pro forma results for the six month period ended June 30, 2026 are shown below, as if the Frontera Transaction had occurred on January 1, 2025. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	$	1,205,557
Net revenue less direct costs	$	569,531

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 net income and comprehensive income for the six months ended June 30, 2026 includes $129.5 million of oil and natural gas sales attributable to the assets acquired since the Frontera Transaction. Revenue less direct costs for the six months ended June 30, 2026 attributable to the assets acquired since the Frontera Transaction is $39.7 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 net income and 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	$	508,468
Net revenue less direct costs or operating netback(1)	$	299,815

(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 net income and comprehensive income for the six months ended June 30, 2025 includes $11.3 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the six months ended June 30, 2025 attributable to the assets acquired since the LLA-32 Acquisition is $7.3 million.

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		7,224
Transfers to E&E and PP&E assets		(14,558)
Sale of inventory		(726)
Balance at June 30, 2026	**$**	**167,366**

The table below represents the other long-term inventory expenditures for the three and six months ended June 30, 2026 and 2025:

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2026**	2025	**2026**	2025
Additions	**$ 5,547**	$ 5,147	**$ 7,224**	$ 5,877
Transfers to D&P and E&E assets	**(6,607)**	(7,076)	**(14,558)**	(11,510)
Transfer to production costs	**—**	(1,040)	**—**	(1,984)
Sale of inventory	**(183)**	(698)	**(726)**	(698)
Total long-term inventory expenditures, net of transfers and sales	**$ (1,243)**	$ (3,667)	**$ (8,060)**	$ (8,315)

Summary of Quarterly Results

Three months ended ($000s) (except per share amounts)		**Jun. 30, 2026**		Mar. 31, 2026		Dec. 31, 2025		Sep. 30, 2025
Average daily production								
Light Crude Oil and Medium Crude Oil (bbl/d)		**14,515**		13,726		14,664		10,257
Heavy Crude Oil (bbl/d)		**37,130**		29,269		32,267		32,026
Natural gas liquids (boe/d)		**765**		254		171		268
Crude Oil (bbl/d)		**52,410**		43,249		47,102		42,551
Conventional Natural Gas (mcf/d)		**10,266**		8,916		9,024		8,412
Total (boe/d)		**54,121**		44,735		48,606		43,953
Realized sales price - oil ($/bbl)(6)		**91.48**		67.70		56.70		62.32
Financial ($000s except per share amounts)								
Oil and natural gas sales	**$**	**466,016**	$	271,377	$	248,713	$	252,424
Funds flow provided by operations(5)	**$**	**132,054**	$	113,702	$	122,922	$	105,298
Per share – basic(2)(4)		**1.37**		1.18		1.28		1.09
Per share – diluted(2)(4)		**1.37**		1.18		1.28		1.09
Adjusted Funds flow provided by operations(5)	**$**	**191,155**	$	116,548	$	122,115	$	108,491
Per share – basic(2)(4)		**1.99**		1.21		1.27		1.12
Per share – diluted(2)(4)		**1.98**		1.21		1.27		1.12
Net income	**$**	**444,296**	$	4,589	$	74,865	$	50,476
Per share – basic(4)		**4.62**		0.05		0.78		0.52
Per share – diluted(4)		**4.61**		0.05		0.78		0.52
Dividends paid	**$**	**26,483**	$	26,937	$	26,853	$	26,892
Per share - Cdn$(4)(6)		**0.385**		0.385		0.385		0.385
Capital Expenditures(1)	**$**	**133,693**	$	91,043	$	84,620	$	79,961
Total assets (end of period)	**$**	**4,235,530**	$	2,496,102	$	2,341,092	$	2,260,531
Outstanding shares (end of period) (000s)		**96,180**		96,115		95,974		96,564
Net debt (net cash)(5)	**$**	**906,598**	$	39,694	$	4,973	$	13,167
Working capital surplus (end of period)(3)(5)	**$**	**(83,222)**	$	135,506	$	28,027	$	(3,167)

Three months ended ($000s) (except per share amounts)	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	Sep. 30, 2024
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,182	10,276	9,290	8,774
Heavy Crude Oil (bbl/d)	31,047	32,207	34,882	37,777
Natural gas liquids (boe/d)	316	374	260	290
Crude Oil (bbl/d)	41,545	42,857	44,432	46,841
Conventional Natural Gas (mcf/d)	5,982	4,806	5,190	4,368
Total (boe/d)	42,542	43,658	45,297	47,569
Realized sales price - oil ($/bbl)(6)	61.07	67.05	64.01	69.07
Financial ($000s except per share amounts)				
Oil and natural gas sales	$ 239,070	$ 265,635	$ 277,824	$ 302,033
Funds flow provided by operations(5)	$ 104,821	$ 121,944	$ 141,201	$ 151,773
Per share – basic(2)(4)	1.08	1.24	1.43	1.50
Per share – diluted(2)(4)	1.08	1.24	1.43	1.50
Adjusted Funds flow provided by operations(5)	$ 103,653	$ 123,305	$ 141,201	$ 151,773
Per share – basic(2)(4)	1.06	1.26	1.43	1.50
Per share – diluted(2)(4)	1.06	1.26	1.43	1.50
Net income (loss)	$ 49,113	$ 80,629	$ (69,051)	$ 65,793
Per share – basic(4)	0.50	0.82	(0.70)	0.65
Per share – diluted(4)	0.50	0.82	(0.70)	0.65
Dividends paid	$ 27,561	$ 26,365	$ 26,658	$ 28,467
Per share - Cdn$(4)(6)	0.385	0.385	0.385	0.385
Capital Expenditures(1)	$ 88,690	$ 57,054	$ 82,110	$ 82,367
Total assets (end of period)	$ 2,223,178	$ 2,197,955	$ 2,155,062	$ 2,290,683
Outstanding shares (end of period) (000s)	97,184	97,814	98,339	100,031
Net debt (net cash)(5)	(2,048)	(19,040)	603	(7,509)
Working capital surplus (end of period)(3)(5)	$ 20,048	$ 69,040	$ 59,397	$ 37,509

(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). The acquisition of Frontera Energy Corporation’s exploration and production assets, completed on June 1, 2026, also impacted quarter-over-quarter trends through the inclusion of the acquired operations’ production, revenue, operating expenses and other financial statement items.

Net income is also impacted by changes in non-cash impairment of property, plant and equipment, exploration and evaluation and long term-inventory assets, as well as acquisition-related accounting adjustments, including fair value adjustments recognized as part of the purchase price allocation. 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 expenditures and long-term inventory expenditures in accordance with the Company’s activities, as well as the timing of settlement of receivables, payables and income taxes. Quarter-over-quarter working capital changes also reflect the impact of the Frontera Transaction, including the assumption of acquired working capital balances, debt-related balances and other liabilities recognized at fair value on the acquisition date. Financing activities, including bank debt borrowings or repayments, the issuance or repayment of debt, and the cost associated with share repurchases and dividend payments, also impact working capital and liquidity trends.

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. The Company primarily 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 to include shareholders' equity, the credit facility, unsecured notes and its working capital. As at June 30, 2026, shareholders' equity was $2,351.7 million (December 31, 2025 - $1,952.9 million).

As at June 30, 2026, the Company had a working capital deficit of $83.2 million(1) as compared to a working capital surplus of $28.0 million(1) at December 31, 2025. The decrease was primarily attributable to the acquisition of Frontera and the related assumption of current liabilities, partially offset by higher unrestricted cash balances.

As at June 30, 2026, Parex held $163.3 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 provide additional liquidity and fund cash or letter of credit needs as they arise. As at June 30, 2026, there was no draw on the credit facility (at December 31, 2025 - $33.0 million was drawn). The credit facility is secured by the Company's Colombian assets and has final maturity date of May 31, 2028. The next annual review is scheduled to occur in May 2027. 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, senior secured debt to adjusted EBITDA test of 3.00:1, and other standard business operating covenants for each reporting period. The Company is in compliance with all covenants.

On May 11, 2026, in conjunction with the Frontera Transaction, the Company completed a $500.0 million private placement offering of senior unsecured notes due 2031 ("2031 Unsecured Notes") 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, unless earlier redeemed or repurchased. The interest is payable semi-annually in arrears on November 11 and May 11 of each year, beginning on November 11, 2026. The carrying value for the 2031 Unsecured Notes as at June 30, 2026 was $485.0 million compared to the fair value of $508.0 million (Level 2 input). Gross proceeds from the issuance were $500.0 million, with initial carrying amount of $484.6 million after deducting the initial offering expenses payable by the Company of $15.4 million. Key covenants include a fixed charge test of not less than 2.25:1 and net 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 June 30, 2026.

As part of the Frontera Transaction, the Company assumed all of Frontera's obligations under its $310.0 million aggregate principal amount of 7.875% senior unsecured notes due 2028 ("2028 Unsecured Notes") issued on June 21, 2021. The interest is payable semi-annually in arrears on June 21 and December 21 of each year, beginning on December 21, 2021. The 2028 Unsecured Notes will mature June 21, 2028, unless earlier redeemed or repurchased. The carrying value for the 2028 Unsecured Notes as at June 30, 2026 was $307.3 million compared to the fair value of $308.8 million (Level 2 input). Key covenants include a fixed charge test of not less than 2.25:1 and net debt to adjusted EBITDA test of 3.25:1 and other standard business operating covenants for each reporting period. The Company was in compliance with all key covenants at June 30, 2026.

The 2028 and 2031 unsecured notes are subordinated to secured debt to the extent of the value of the assets securing such indebtedness.

Refer to note 27 - Commitments and Contingencies of the interim financial statements for the period ended June 30, 2026 for information regarding performance guarantees and 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 June 30, 2026 the Company had 96,180,254 common shares outstanding compared to 95,974,136 at December 31, 2025. At July 30, 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 July 30, 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 Contingencies

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.

The following table summarizes the Company's estimated undiscounted commitments as at June 30, 2026:

	2026	2027	2028	2029	2030	Thereafter	Total
Exploration and Evaluation							
Minimum work commitments	$ 40,655	$ 143,911	$ 104,155	$ 11,689	$ —	$ 405,504	705,914
Transportation	13,884	2,554	—	—	—	—	16,438
Operating leases	1,228	2,271	623	—	—	—	4,122
Other commitments							
Purchased oil	58,325	—	—	—	—	—	58,325
Energy supply commitments	16,630	12,537	13,109	8,249	8,495	8,741	67,761
Decommissioning and Environmental Obligations	27,707	—	—	—	—	714,309	742,016
Total	**$ 158,429**	**$ 161,273**	**$ 117,887**	**$ 19,938**	**$ 8,495**	**$1,128,554**	**$1,594,576**

Exploration and Evaluation Minimum work commitments

At June 30, 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 $504.1 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 June 30, 2026 in respect of the Colombia work commitments under E&P contracts, and joint venture farm-in arrangements, is as disclosed above.

Transportation
Includes ship-or-pay contracts with Bicentenario and Cenit where the pledged inventory crude oil is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. A pledge agreement with Ocensa and Cenit is in place, which guarantees the payment obligations of both contracts.

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 June 30, 2026 are as disclosed above.

Purchased oil
Includes an agreement in place covering crude oil purchases for 2026.

Energy supply
Includes executed contracts for grid-connected, on-site generation, and solar power sources, ensuring the electricity supply across operational blocks, particularly Quifa and CPE-6.

Contingencies
The Company is involved in various claims and litigation arising from the normal course of business. Given the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. Management has assessed the likelihood of settlement and determined the best estimate based on relevant information and the probability of outcomes. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

Refer to Note 8 - Business Combinations of the condensed interim financial statements for the period ended June 30, 2026 regarding the contingent payment agreed to as part of the consideration of the Frontera Transaction.

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 9	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	10,772	2,723	13,495
Acquired on close of business combination - Note 8	156,249	23,750	179,999
Discount rate adjustment on obligations acquired	32,355	5,894	38,249
Settlements of obligations during the period	(8,614)	(2,450)	(11,064)
Gain on settlement of obligations	(1,046)	(175)	(1,221)
Accretion expense	5,442	826	6,268
Change in estimate - inflation and discount rates	17,830	4,264	22,094
Change in estimate - costs and timing of settlements	(5,014)	935	(4,079)
Foreign exchange loss	5,537	3,120	8,657
Balance, June 30, 2026	**$ 291,074**	**$ 50,489**	**$ 341,563**
Current obligation	(18,572)	(9,135)	(27,707)
Long-term obligation	**$ 272,502**	**$ 41,354**	**$ 313,856**

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 June 30, 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 $641.6 million as at June 30, 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 11.4% 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 $18.6 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 $100.4 million as at June 30, 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 11.4% 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 $9.1 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

Ecopetrol Strategic Partnership

Previously, on May 4, 2026, the Company announced that it had executed an agreement with its strategic partner Ecopetrol S.A., whereby the Company will earn a 50% participating share in the Casabe and Llanito blocks in the Magdalena Basin of Colombia, upon spudding the first well on each block. The assets currently produce approximately 15,000 bbl/d of medium crude oil (gross).This production is expected to add a stable, cash-generating base to Parex's portfolio while also establishing a new core operating and development area for future growth.

With the agreement closed as of July 29, 2026, and all regulatory approvals received, Parex plans to spud its first wells during H2 2026 and trigger its participating share on each block.

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 portion of its site restoration costs 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 anticipated H2 2026 production, transportation and G&A expenses 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;
- 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;
- expectations regarding the integration of the Frontera assets and realization of anticipated synergies and benefits therefrom;
- expectations regarding Parex's participation in the Casabe and Llanito blocks in the Magdalena Basin under its business collaboration with Ecopetrol, including the current approximate production and timing of first well spud thereunder;
- anticipated timing of spudding the Company's first well at the Piedemonte prospect in Fall 2026 and commencement of civil works;
- expectations regarding exploration success at LLA-111, the expansion of a multi-field development in the Eastern Llanos, current and anticipated production levels therefrom, and the anticipated long-term production capacity trajectory;
- anticipated timing of beginning civil works at Farallones in H2 2026;
- expectations regarding the identification and capture of operational and strategic synergies from the Frontera Transaction, including in marketing, supply chain, tax and other functions, and the expected timing of realizing associated benefits;
- performance projections in connection with elevated energy costs, including expectations that production expense will trend toward the upper end of H2 2026 guidance;
- 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, including the integration of the Frontera assets; 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; risks related to the integration of the Frontera assets and the realization of the anticipated synergies and benefits therefrom; risk related to the Ecopetrol partnership, including the timing of first production, the execution of the capital program, and the realization of anticipated benefits therefrom; 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; 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 successful integration of the Frontera assets and the realization of anticipated synergies and benefits therefrom; the successful execution of the Ecopetrol partnership arrangement including the timing of first production and capital commitments and the realization of anticipated benefits 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. readers are cautioned not to place undue reliance of forward-looking information. 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 constitute a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to: Parex's H2 and 2026 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, and should not be used for purposes other than for which it is disclosed herein.

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 and Gas 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:*

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2026**	2025	**2026**	2025
Property, plant and equipment expenditures	**$ 69,131**	$ 49,067	**$ 117,413**	$ 94,018
Exploration and evaluation expenditures	**64,562**	39,623	**107,323**	51,726
Capital expenditures	**$ 133,693**	$ 88,690	**$ 224,736**	$ 145,744

	For the three months ended					
($000s)	March 31, 2026	December 31, 2025	September 30, 2025	March 31, 2025	December 31, 2024	September 30, 2024
Property, plant and equipment expenditures	$ 48,282	$ 47,575	$ 59,002	$ 44,951	$ 62,799	$ 68,406
Exploration and evaluation expenditures	42,761	37,045	20,959	12,103	19,311	13,961
Capital expenditures	$ 91,043	$ 84,620	$ 79,961	$ 57,054	$ 82,110	$ 82,367

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:*

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2026**	2025	**2026**	2025
Cash provided by operating activities	**$ 199,235**	$ 142,642	**$ 223,321**	$ 230,020
Net change in non-cash assets and liabilities	**(67,181)**	(37,821)	**22,435**	(3,255)
Funds flow provided by operations	**132,054**	104,821	**245,756**	226,765
Capital expenditures, excluding corporate acquisitions	**133,693**	88,690	**224,736**	145,744
Free funds flow	**$ (1,639)**	$ 16,131	**$ 21,020**	$ 81,021

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, gain on acquisition, transaction costs, non-cash inventory fair value adjustment, 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:

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2026**	2025	**2026**	2025
Net income	**$ 444,296**	$ 49,113	**$ 448,885**	$ 129,742
Adjustments to reconcile net income to EBITDA:				
Finance income	**(2,740)**	(612)	**(6,144)**	(1,909)
Finance expense	**17,219**	5,474	**23,984**	10,530
Other expense	**8,970**	12,453	**26,327**	13,600
Income tax expense (recovery)	**(42,576)**	9,623	**(23,342)**	12,701
Depletion, depreciation and amortization	**62,382**	47,949	**113,671**	98,368
EBITDA	**$ 487,551**	$ 124,000	**$ 583,381**	$ 263,032
Share-based compensation expense	**(341)**	6,476	**18,326**	8,568
Gain on acquisition	**(302,483)**	—	**(302,483)**	—
Transaction costs	**28,390**	—	**29,000**	—
Non-cash inventory fair value adjustment	**9,365**	—	**9,365**	—
Unrealized foreign exchange gain	**(2,217)**	(2,369)	**(1,507)**	(7,288)
Unrealized gain on commodity risk management contracts	**(30,635)**	(362)	**(1,050)**	(1,160)
Unrealized (gain) loss on marketable securities	**2,433**	—	**(10,285)**	—
Adjusted EBITDA	**$ 192,063**	$ 127,745	**$ 324,747**	$ 263,152

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 purchased crude oil, royalties, production, 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 produced oil and gas sales volumes before consumption for oil and natural gas sales price, oil and natural gas sales price, net of purchased crude oil, royalties, production and transportation 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 before consumption. 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.*

Adjusted funds flow provided by operations per share*, is a non-GAAP ratio that is calculated by dividing adjusted funds flow provided by operations by the weighted average number of basic and diluted shares outstanding. Parex presents basic and diluted adjusted funds flow provided by operations excluding the one-time costs of nonrecurring transaction-related costs and realized losses on hedging contracts 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 adjusted 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 excluding items that may not reflect ongoing operating performance, relative to current commodity prices.*

Adjusted funds flow provided by operations netback per boe, *is a capital management measure calculated as funds flow provided by operations, adjusted to exclude non-recurring transaction-related costs and realized (gains) losses on commodity risk management contracts. The Company considers adjusted funds flow provided by operations to be a key measure as it demonstrates Parex's profitability after cash costs, excluding items that may not reflect ongoing operating performance, 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.*

***Basic and diluted adjusted funds flow provided by operations per share or FFO per share**, is a non-GAAP ratio that is calculated by dividing adjusted funds flow provided by operations by the weighted average number of basic and diluted shares outstanding. Parex presents basic and diluted adjusted funds flow provided by operations adjusted to exclude non-recurring transaction-related costs and realized (gains) losses on commodity risk management contracts 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 adjusted 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 excluding items that may not reflect ongoing operating performance, relative to current commodity prices.*

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.*

***Adjusted funds flow provided by operations,** is a capital management measure calculated as funds flow provided by operations, adjusted to exclude non-recurring transaction-related costs and realized (gains) losses on commodity risk management contracts. The Company considers adjusted funds flow provided by operations to be a key measure as it demonstrates Parex's profitability after cash costs, excluding items that may not reflect ongoing operating performance.*

A reconciliation from cash provided by operating activities to funds flow provided by operations and adjusted funds flow provided by operations is as follows:

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2026**	2025	**2026**	2025
Cash provided by operating activities	**$ 199,235**	$ 142,642	**$ 223,321**	$ 230,020
Net change in non-cash assets and liabilities	**(67,181)**	(37,821)	**22,435**	(3,255)
Funds flow provided by operations	**132,054**	104,821	**245,756**	226,765
Transaction costs	**28,390**	—	**29,000**	—
Realized loss (gain) on commodity risk management contracts	**30,711**	(1,168)	**32,947**	193
Adjusted funds flow provided by operations	**$ 191,155**	$ 103,653	**$ 307,703**	$ 226,958

	For the three months ended					
($000s)	March 31, 2026	December 31, 2025	September 30, 2025	March 31, 2025	December 31, 2024	September 30, 2024
Cash provided by operating activities	$ 24,086	$ 107,744	$ 86,992	$ 87,621	$ 67,847	$ 181,874
Net change in non-cash assets and liabilities	89,616	15,178	18,306	34,323	73,354	(30,101)
Funds flow provided by operations	113,702	122,922	105,298	121,944	141,201	151,773
Transaction costs	610	—	—	—	—	—
Realized (gain) loss on commodity risk management contracts	2,236	(807)	3,193	1,361	—	—
Adjusted funds flow provided by operations	$ 116,548	$ 122,115	$ 108,491	$ 123,305	$ 141,201	$ 151,773

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:*

	As at June 30,	
($000s)	**2026**	2025
Current assets	**$ 602,247**	$ 239,485
Current liabilities	**685,469**	219,437
Working capital (deficit) surplus	**$ (83,222)**	$ 20,048

	As at					
($000s)	March 31, 2026	December 31, 2025	September 30, 2025	March 31, 2025	December 31, 2024	September 30, 2024
Current assets	$ 411,425	$ 273,994	$ 224,109	$ 259,256	$ 245,943	$ 248,208
Current liabilities	275,919	245,967	227,276	190,216	186,546	210,699
Working capital surplus (deficit)	$ 135,506	$ 28,027	$ (3,167)	$ 69,040	$ 59,397	$ 37,509

Net debt (net cash), *is a capital management measure which the Company uses to monitor leverage and manage capital. Net debt (net cash) is defined as working capital, less bank debt, unsecured notes and long-term customer prepayments:*

	As at June 30,	
($000s)	**2026**	2025
Working capital deficit (surplus)	**$ 83,222**	$ (20,048)
Bank debt	**—**	18,000
Unsecured notes	**792,265**	—
Customer prepayments - long-term	**31,111**	—
Net debt (net cash)	**$ 906,598**	$ (2,048)

	As at					
($000s)	March 31, 2026	December 31, 2025	September 30, 2025	March 31, 2025	December 31, 2024	September 30, 2024
Working capital (surplus) deficit	$ (135,506)	$ (28,027)	$ 3,167	$ (69,040)	$ (59,397)	$ (37,509)
Bank debt	175,200	33,000	10,000	50,000	60,000	30,000
Net debt (net cash)	$ 39,694	$ 4,973	$ 13,167	$ (19,040)	$ 603	$ (7,509)

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 produced oil and gas sales volumes before consumption.

"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 equivalent produced oil and gas sales volumes before consumption.

"Oil and natural gas sales price, net of purchased crude oil per boe" is comprised of total commodity sales from oil and natural gas production less purchased crude oil, 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 produced oil and gas sales volumes before consumption.

"Purchased crude oil per boe" is comprised of purchased crude oil expense, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

"Realized oil sales price per bbl" is comprised of total oil sales, as determined in accordance with IFRS, divided by the total equivalent produced oil sales volumes before consumption.

"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 produced oil and gas sales volumes before consumption.

"Royalties as a percentage of sales" is comprised of royalties, as determined in accordance with IFRS, divided by the total equivalent sales from produced oil and natural gas production, 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 equivalent produced oil sales volumes before consumption.

"Transportation expense per boe" is comprised of transportation expense, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

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

During the period ended June 30, 2026, Parex completed the acquisition of Frontera Petroleum International Holdings B.V. (the "Frontera Transaction"), which holds all of Frontera's exploration and production assets in Colombia. The Company began consolidating the results of the acquired business effective June 1, 2026. In connection with the Frontera Transaction, management commenced activities to integrate the acquired operations, processes and systems into Parex's disclosure controls and procedures ("DCP") and internal control over financial reporting ("ICFR").

As permitted by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, management has limited the scope of its design of DCP and ICFR to exclude the controls, policies and procedures of the acquired Frontera business as at June 30, 2026. National Instrument 52-109 permits an issuer to limit the scope of the design of DCP and ICFR to exclude an acquired business for a period of up to 365 days from the acquisition date. During this period, management will continue its assessment and integration of the acquired business, including the design and implementation of appropriate controls.

At June 30, 2026, the acquired business represented approximately 43% of the Company's consolidated total assets and approximately 18% of the Company's consolidated oil and natural gas sales for the period from the acquisition date of June 1, 2026 to June 30, 2026.

Other than changes associated with the integration of the acquired Frontera business described above, there were no changes in the Company's ICFR during the period covered by this MD&A that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the six months ended June 30, 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 27 - 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 relate to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. There was not a material effect to 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.

In addition, due to the acquisition of Frontera Petroleum International Holdings B.V. (see Note 8 - Business Combination), the following additional accounting policies have been updated:

Subsidiaries:
Frontera Energy Colombia AG has been identified as an additional principal operating subsidiary. Frontera Energy AG is incorporated in Switzerland and its principle business activity is oil and natural gas exploration and development in Colombia. Parex has 100% ownership of this subsidiary.

Customer prepayments:
The Company recognizes each contract in the statement of financial position as either a contract asset or a contract liability, based on the relationship between the Company’s performance under the contract and the consideration received from the customer. Additionally, when a customer pays consideration, or when the Company has an unconditional right to consideration (i.e., a receivable) before transferring goods or services, the entity shall present the amount as a contract liability or customer prepayment in the statement of financial position (see Note 13 - Customer Prepayments). This classification applies at the earlier of the payment date or the date the payment becomes due. Financing components embedded in customer prepayment arrangements are recognized using the effective interest method over the term of the agreement when significant financing components exist.

In addition, due to the recognition of Equity tax in the current period, the following additional accounting policy has been updated:

Equity tax:
Equity tax represents a tax imposed by the Colombian Government on entities whose net equity exceeds a prescribed threshold as of a specified measurement date. The tax is recognized as an expense when the obligating event occurs and the amount can be reliably estimated. The related liability is measured based on the applicable tax rate applied to taxable net equity, considering enacted or substantively enacted tax legislation at the reporting date. Equity tax is recognized in profit or loss and is not included in income tax expense unless required by applicable tax legislation (see Note 20 - Other Expense).

Standards Issued but not yet Effective

i) IFRS 18 Presentation and Disclosure in Financial Statements
In April 2024, the IASB issued IFRS 18 Presentation and Disclosure in Financial Statements ("IFRS 18") which will replace IAS 1 and includes requirements for all entities applying IFRS for the presentation and disclosure of information in the financial statements. IFRS 18 will introduce new totals, subtotals and categories for income and expenses in the statement of income, as well as requiring disclosure about management-

defined performance measures ("MPMs") and additional requirements regarding the aggregation and disaggregation of certain information. The new guidance is expected to improve the usefulness of information presented and disclosed in the financial statements of companies. IFRS 18 will be effective for annual reporting periods beginning on or after January 1, 2027, with early adoption permitted, and it must be adopted on a retrospective basis.

Parex is currently assessing the impact of this new IFRS accounting standard on its consolidated financial statements. Throughout 2026, Parex will assess system changes, draft and finalize financial statements to quantify the impact of changes, MPMs and related disclosures ahead of the 2027 effective date.

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.

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Sigmund Cornelius

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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