

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 September 30, 2025 is dated November 3, 2025 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the period ended September 30, 2025, as well as the Company's audited consolidated annual financial statements for the year ended December 31, 2024. 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 Accounting Standards"), 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 4, 2025 ("AIF"), and may be accessed through the SEDAR+ website at www.sedarplus.ca.

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

Company Profile

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

Abbreviations

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

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

Three months ended September 30, 2025 ("third quarter" or "Q3") Highlights

- Recognized net income of \$50.5 million (\$0.52 per share basic) compared to net income of \$65.8 million (\$0.65 per share basic) in the comparative quarter of 2024. The decrease from the comparative quarter is largely related to a decrease in oil revenues from lower oil volumes sold and a decrease in realized sales price, partially offset by a decrease in deferred tax expense.
- Generated quarterly funds flow provided by operations ("FFO")⁽¹⁾ of \$105.3 million (\$1.09 per share basic⁽²⁾) compared to \$151.8 million (\$1.50 per share basic⁽²⁾) in the comparative quarter of 2024.
- Produced an operating netback of \$34.71/boe⁽²⁾ (Q2 2025 - \$36.25/boe⁽²⁾) and an FFO netback of \$26.04/boe⁽²⁾ (Q2 2025 - \$26.90/boe⁽²⁾) from an average Brent price of \$68.17/bbl (Q2 2025 - \$66.71/bbl). Strong netbacks were supported by favourable oil price differentials.
- Incurred \$80.0 million of capital expenditures⁽³⁾.
- Generated \$25.3 million of free funds flow⁽³⁾; bank debt was \$10.0 million after repayment during the quarter of \$8.0 million and cash was \$69.8 million at quarter end.
- Paid a C\$0.385 per share⁽⁴⁾ regular quarterly dividend and repurchased 620,000 shares pursuant to the Company's normal course issuer bid ("NCIB").

(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

Parex's 2025 average production guidance of 43,000 to 47,000 boe/d and capital expenditure guidance of \$285 to \$315 million remains unchanged. The Company expects that Q4 2025 average production will exceed the higher end of the annual guidance range. With regard to capital expenditures, the Company expects to be toward the higher end of its previously disclosed capital expenditure range of \$285 to \$315 million, based on success-driven follow-up drilling and added Capachos development wells, slightly offset by slower-than-expected spending in the Putumayo. Contingent on continued success, the Company may consider adding additional capital in late Q4 2025 to sustain momentum into 2026.

Financial Summary

	For the three months ended September 30,		For the nine months ended September 30,	
(Financial figures in \$'000s except per share amounts)	2025	2024	2025	2024
Light Crude Oil and Medium Crude Oil (bbl/d)	10,525	9,064	10,557	8,615
Heavy Crude Oil (bbl/d)	32,026	37,777	31,759	42,167
Average oil production (bbl/d)	42,551	46,841	42,316	50,782
Average conventional natural gas production (mcf/d)	8,412	4,368	6,414	4,170
Average oil and natural gas production (boe/d)	43,953	47,569	43,385	51,477
Production split (% crude oil)	97	98	98	99
Oil and natural gas sales price (\$/boe) ⁽⁶⁾	62.41	68.75	63.68	71.69
Operating netback (\$/boe) ⁽¹⁾	34.71	39.64	36.77	43.28
Oil and natural gas sales	252,424	302,033	757,129	1,002,205
Funds flow provided by operations ⁽⁷⁾	105,298	151,773	332,063	481,032
Per share – basic ⁽¹⁾⁽³⁾	1.09	1.50	3.41	4.71
Per share – diluted ⁽¹⁾⁽³⁾	1.09	1.50	3.41	4.71
Net income	50,476	65,793	180,218	129,731
Per share – basic ⁽³⁾	0.52	0.65	1.85	1.27
Per share – diluted ⁽³⁾	0.52	0.65	1.85	1.27
Dividends paid	26,892	28,467	80,818	85,526
Per share - Cdn\$ ⁽³⁾⁽⁶⁾	0.385	0.385	1.155	1.145
Share repurchases	7,606	20,723	18,870	57,381
Number of shares repurchased (000s)	620	1,585	1,775	3,803
Capital expenditures ⁽²⁾	79,961	82,367	225,705	265,585
Long-term inventory expenditures	(1,585)	(6,318)	(9,900)	7,342
Free funds flow ⁽²⁾	25,337	69,406	106,358	215,447
EBITDA ⁽²⁾	113,648	167,763	376,680	555,781
Adjusted EBITDA ⁽²⁾	121,133	164,002	384,284	582,777
Total assets (end of period)	2,260,531	2,290,683	2,260,531	2,290,683
Working capital (deficit) surplus (end of period) ⁽⁴⁾⁽⁷⁾	(3,167)	37,509	(3,167)	37,509
Bank debt (end of period) ⁽⁵⁾	10,000	30,000	10,000	30,000
Weighted average shares outstanding (000s)				
Basic	96,874	100,891	97,492	102,203
Diluted	96,956	100,891	97,501	102,203
Outstanding shares (end of period) (000s)	96,564	100,031	96,564	100,031

(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 September 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

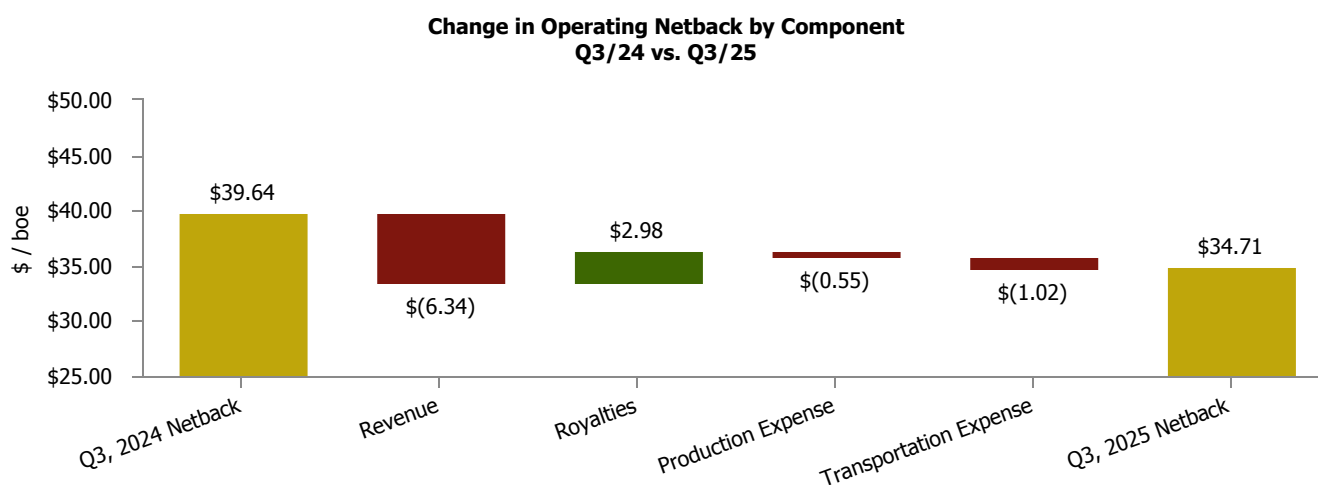
Parex's oil and gas operations are conducted in Colombia with head office functions conducted in Canada.

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,525	9,064	10,557	8,615
Heavy Crude Oil (bbl/d)	32,026	37,777	31,759	42,167
Crude Oil (bbl/d)	42,551	46,841	42,316	50,782
Conventional Natural Gas (mcf/d)	8,412	4,368	6,414	4,170
Total (boe/d)	43,953	47,569	43,385	51,477
Production split (% crude oil production)	97	98	98	99
Average daily sales of oil and natural gas				
Produced crude oil (bbl/d)	42,559	46,977	42,476	50,289
Purchased crude oil (bbl/d)	—	47	4	37
Produced natural gas (mcf/d)	8,412	4,368	6,414	4,170
Total (boe/d)	43,961	47,752	43,549	51,021
Operating netback (\$000s)				
Oil and natural gas sales	\$ 252,424	\$ 302,033	\$ 757,129	\$ 1,002,205
Royalties	(30,785)	(46,470)	(98,103)	(160,324)
Net revenue	221,639	255,563	659,026	841,881
Production expense	(62,120)	(65,005)	(168,470)	(187,570)
Transportation expense	(19,124)	(16,299)	(53,363)	(48,868)
Purchased oil	—	(388)	(162)	(845)
Operating netback ⁽¹⁾	\$ 140,395	\$ 173,871	\$ 437,031	\$ 604,598
Operating netback (per boe)				
Brent (\$/bbl)	\$ 68.17	\$ 78.71	\$ 69.91	\$ 81.82
Parex price differential	(5.76)	(9.96)	(6.23)	(10.13)
Oil and natural gas sales ⁽²⁾	62.41	68.75	63.68	71.69
Royalties ⁽²⁾	(7.61)	(10.59)	(8.25)	(11.48)
Net revenue ⁽²⁾	54.80	58.16	55.43	60.21
Production expense ⁽²⁾	(15.36)	(14.81)	(14.17)	(13.43)
Transportation expense ⁽²⁾	(4.73)	(3.71)	(4.49)	(3.50)
Operating netback ⁽³⁾	\$ 34.71	\$ 39.64	\$ 36.77	\$ 43.28

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

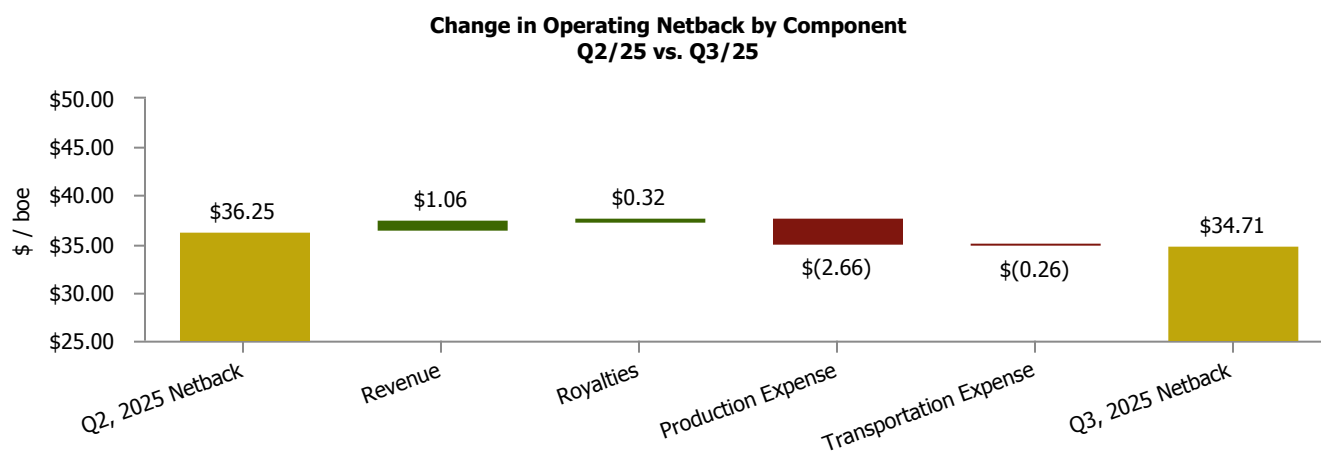
(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

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



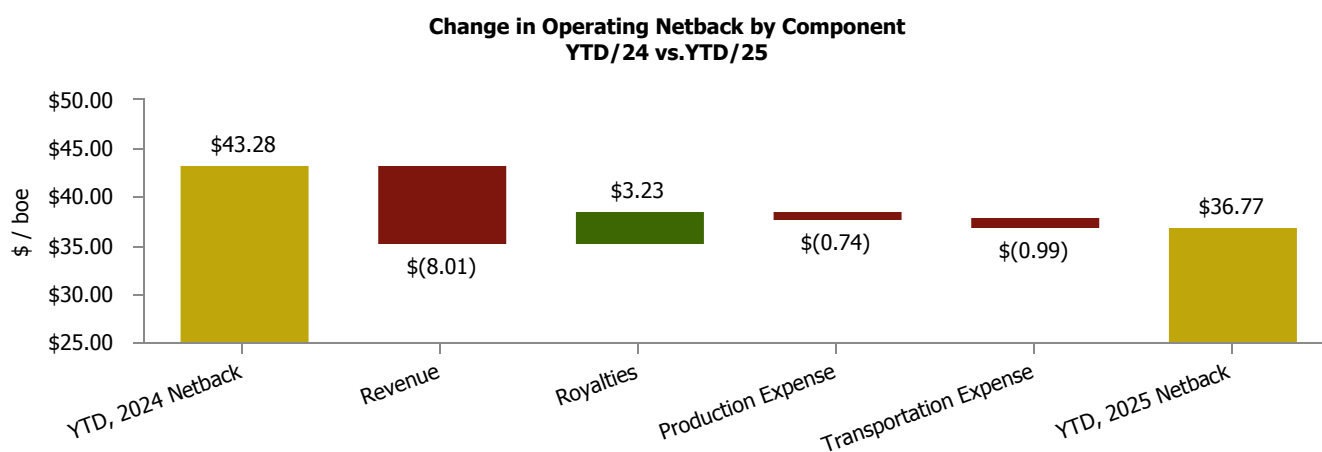
Overall, the Company's benchmark Brent crude oil price decreased by \$10.54/bbl, while revenue decreased by \$6.34/boe in the third quarter of 2025 as compared to the third quarter of 2024. The increase in revenue relative to the Brent crude benchmark decrease was attributable to improved location and quality differentials, decrease in wellhead sales and increase in gas sales volumes and price. Royalties decreased by \$2.98/boe in the quarter compared to the third quarter of 2024 as a result of lower production in areas where high price share royalties are applicable and decrease in world oil prices. Production expense in the quarter increased by \$0.55/boe compared to the third quarter of 2024 due to increased electrical power costs, non-operated production costs, fixed cost absorption and the appreciation of the Colombian peso, partially offset by lower well workovers and facility maintenance. Transportation expense in the quarter increased by \$1.02/boe compared to the third quarter of 2024 primarily due to an increase in the volume of oil production transported by truck and higher gas volumes transported.

Overall, the operating netback decreased by \$4.93/boe compared to a Brent benchmark crude price decrease of \$10.54/bbl.



In the third quarter of 2025, the Company's benchmark Brent oil price increased by \$1.46/bbl, while revenue increased by \$1.06/boe as compared to the second quarter of 2025. The decrease in revenue relative to the Brent crude benchmark increase was the result of increased location and quality differentials and wellhead sales discount and decrease in gas sales price. Royalties decreased by \$0.32/boe primarily associated to lower production in areas where high price share royalties are applicable. Production expense increased by \$2.66/boe due to increased electrical power costs, non-operated production costs, fixed cost absorption and the appreciation of the Colombian peso, partially offset by lower well workovers and facility maintenance. Transportation expense in the quarter increased by \$0.26/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 decreased by \$1.54/boe compared to a Brent benchmark crude price increase of \$1.46/bbl.



Year to date 2025, the Company's benchmark Brent oil price decreased by \$11.91/bbl, while revenue decreased by \$8.01/boe as compared to the 2024 year to date comparative period. The increase in revenue relative to the Brent crude benchmark decrease was mainly a result of improved location and quality differentials, decrease in wellhead sales and increase in gas sales volumes and price. Royalties decreased by \$3.23/boe as compared to the 2024 year to date comparative period primarily as a result of lower production in areas where high price share royalties are applicable and decrease in world oil prices. Production expense increased by \$0.74/boe due to increased electrical power costs and non-operated production costs and higher fixed cost absorption, partially offset by lower well workovers and facility maintenance and the depreciation of the Colombian peso. Transportation expense as compared to the 2024 year to date comparative period increased by \$0.99/boe primarily due to an increase in the volume of oil production transported by truck and higher gas volumes transported.

Overall, the operating netback decreased by \$6.51/boe compared to a Brent benchmark crude price decrease of \$11.91/bbl.

Oil and Natural Gas Sales and Other Revenue

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Block LLA-34	20,721	24,975	21,476	27,417
Southern Llanos Basin	16,571	15,031	14,845	16,995
Northern Llanos Basin	3,096	4,567	3,795	4,278
Magdalena Basin	2,163	2,268	2,200	2,092
Total Crude Oil Production	42,551	46,841	42,316	50,782
Natural gas production	1,402	728	1,069	695
Total Crude oil and natural gas production	43,953	47,569	43,385	51,477
Crude oil inventory draw (build)	8	136	160	(493)
Average daily sales of produced oil and natural gas	43,961	47,705	43,545	50,984
Purchased oil	—	47	4	37
Sales Volumes	43,961	47,752	43,549	51,021

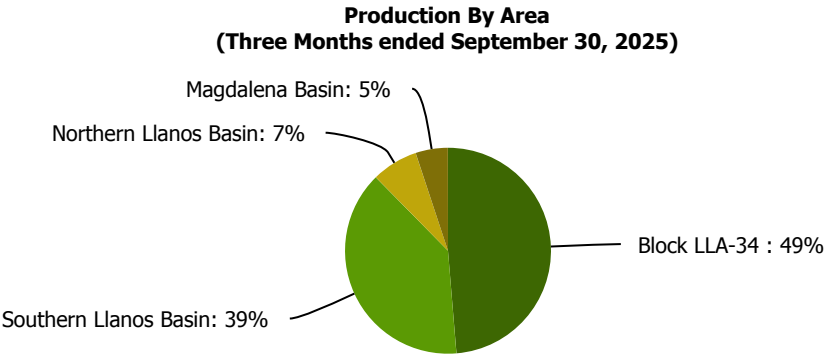
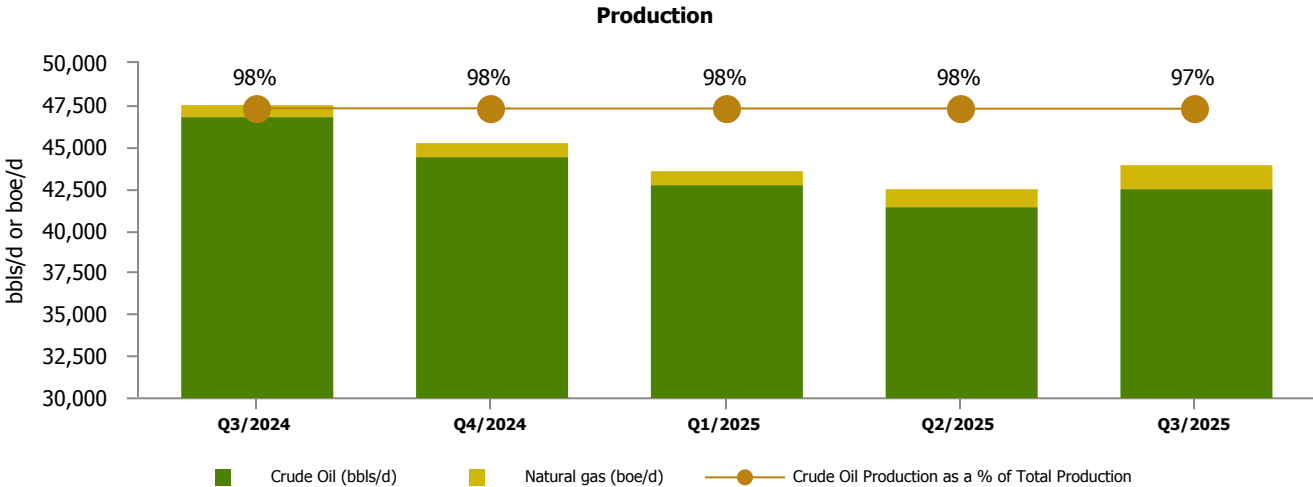
Crude oil and natural gas production for the third quarter of 2025 averaged 43,953 boe/d. October 2025 average production was approximately 49,300 boe/d⁽¹⁾, marking a steady step-up in production being realized as planned. Growth was supported primarily by production ramping-up at Block LLA-32 and near-field exploration success at Block LLA-74.

Crude oil and natural gas production for the third quarter of 2025 of 43,953 boe/d increased approximately 3% compared to the second quarter of 2025 production of 42,542 boe/d and decreased approximately 8% from the third quarter of 2024 production of 47,569 boe/d.

(1) Estimated average production for October 1, 2025 to October 31, 2025; light & medium crude oil: ~11,805 bbl/d, heavy crude oil: ~35,922 bbl/d, conventional natural gas: ~9,435 mcf/d; rounded for presentation purposes.

The decrease in oil and natural gas production in the third quarter of 2025 compared to the third quarter of 2024 is mainly the result of decreased oil production at Block LLA-34 and the Cabrestero Block in the Southern Llanos Basin mainly as a result of natural declines as well as reduced level of new development activity in alignment with a lower capital spending level. These production declines were offset by new added production from Block LLA-74 and the Block LLA-32 fields in the Southern Llanos Basin. Production in the Northern Llanos Basin in the third quarter of 2025 was impacted by operational downtime on the Capachos Block.

Oil and natural gas sales in the third quarter of 2025 were 43,961 boe/d compared to 47,752 boe/d for the third quarter of 2024. The decrease in oil sales volumes was a result of the decrease in oil production from the comparative period.



b) Crude Oil Reference and Realized Prices

Average price for the period	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024
Brent (\$/bbl)	68.17	66.71	74.98	74.01	78.71
Parex location (Vasconia) and quality differential (\$/bbl)	(1.94)	(1.87)	(2.26)	(5.16)	(5.46)
Parex wellhead sales discount (\$/bbl)	(3.91)	(3.77)	(5.67)	(4.84)	(4.18)
Parex realized oil sales price (\$/bbl)⁽²⁾	62.32	61.07	67.05	64.01	69.07
Parex realized price (differential) to Brent crude (\$/bbl)	(5.85)	(5.64)	(7.93)	(10.00)	(9.64)
Parex transportation expense (\$/bbl) ⁽¹⁾⁽²⁾	(4.88)	(4.58)	(4.34)	(3.96)	(3.76)
Parex price differential and transportation expense (\$/bbl)⁽²⁾	(10.73)	(10.22)	(12.27)	(13.96)	(13.40)

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

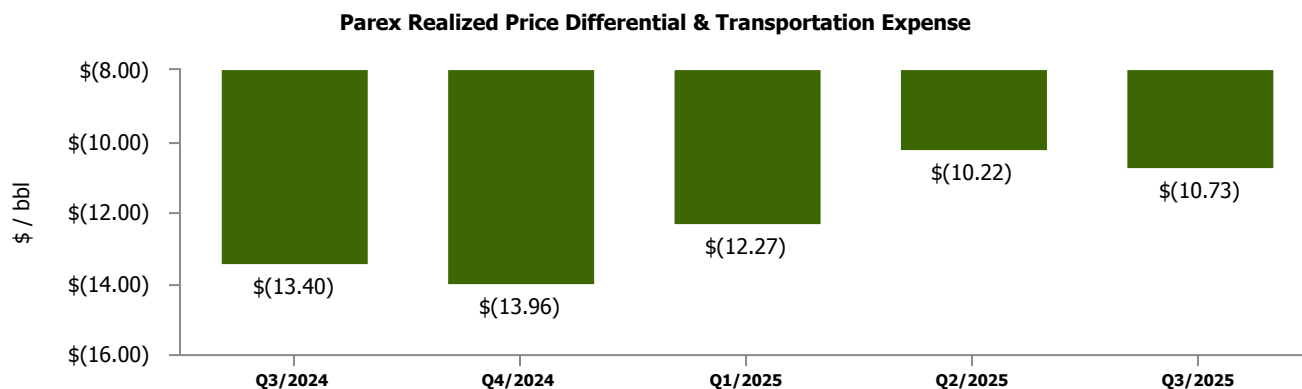
(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

During the third quarter of 2025, the differential between Brent reference pricing and the Company's realized oil sale price was \$5.85/bbl. The differential to Brent crude during the third quarter of 2025 increased by \$0.21/bbl compared to the second quarter of 2025 where the differential was \$5.64/bbl. Compared to the third quarter of 2024 Parex's realized oil price increased from an improved differential of \$9.64/bbl to \$5.85/bbl which was primarily driven by improvements in location and quality differential, mainly due to narrower heavy oil differentials, and a decrease in wellhead sales in favour of direct export sales.

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

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

The current Vasconia differential to Brent is approximately \$2.50/bbl and can fluctuate with oil market conditions. The third quarter 2025 differential of \$1.94/bbl, a vast improvement from the fourth quarter 2024 differential of \$5.16/bbl. This improvement is likely a result of market uncertainty regarding availability of medium/heavy crude oil specifically from Mexico and Venezuela, and tariff tensions impacting world crude pricing.



c) Natural Gas Sales and Realized Prices

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Natural gas sales (\$000's)	\$ 8,421	\$ 3,236	\$ 20,784	\$ 8,975
Realized sales price (\$/Mcf) ⁽¹⁾	10.88	8.05	11.87	7.86

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

Parex's natural gas sales were \$8.4 million and \$20.8 million for the three and nine months ended September 30, 2025 compared to \$3.2 million and \$9.0 million in the comparative periods of 2024. The increase in natural gas sales from the comparative periods of 2024 is primarily related to increased volumes sold from the Capachos and VIM-1 Blocks and increase in realized gas sales price.

d) Oil and Natural Gas Sales

Third quarter 2025 oil and natural gas sales decreased by \$49.6 million or 16% as reconciled in the table below to the third quarter of 2024:

(\$000s)	
Oil and natural gas sales, three months ended September 30, 2024	\$ 302,033
Sales volume of produced oil, a decrease of 9% (4,418 bopd)	(28,074)
Sales volume of purchased oil, a decrease of 100% (47 bopd)	(299)
Oil sales price decrease of 10%	(26,421)
Sales volume and price change of produced natural gas	5,185
Oil and natural gas sales, three months ended September 30, 2025	\$ 252,424

Oil and natural gas sales decreased in the three months ended September 30, 2025 compared to the same period in 2024 mainly due to lower oil volumes sold and a decrease in world oil prices.

e) Crude Oil Inventory in Transit

As at September 30,
(\$000s)

		2025		2024
Crude oil in transit	\$	182	\$	9,880

At September 30, 2025, the Company had 4.9 mbbls of crude oil inventory compared to 240.6 mbbls at September 30, 2024, which was injected into Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at \$37/bbl at September 30, 2025 compared to \$41/bbl at September 30, 2024 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)	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024
Crude oil inventory in transit - beginning of the period	5.5	31.3	48.5	240.6
Oil production	3,914.7	3,780.6	3,857.1	4,087.7
Oil sales	(3,915.3)	(3,806.4)	(3,875.6)	(4,279.8)
Purchased oil	—	—	1.3	—
Crude oil inventory in transit - end of the period	4.9	5.5	31.3	48.5
% of period production	0.1	0.1	0.8	1.2

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

f) Purchased Oil

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Purchased oil expense (\$000s)	\$ —	\$ 388	\$ 162	\$ 845

Purchased oil expense has decreased for the three and nine months ended September 30, 2025 compared to the comparative periods in 2024 as a result of a decrease in oil blending operations and purchases of partner crude oil. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

g) Other Revenue

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Other revenue	\$ 2,168	\$ 2,238	\$ 6,999	\$ 5,418

Royalties

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Base royalties ⁽¹⁾	\$ 20,282	\$ 25,080	\$ 60,911	\$ 84,097
Economic rights ⁽²⁾	10,503	21,390	37,192	76,227
Royalties (\$000s)	\$ 30,785	\$ 46,470	\$ 98,103	\$ 160,324
Per unit (\$/boe) ⁽³⁾	7.61	10.59	8.25	11.48
Percentage of sales ⁽³⁾	12	15	13	16

(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.

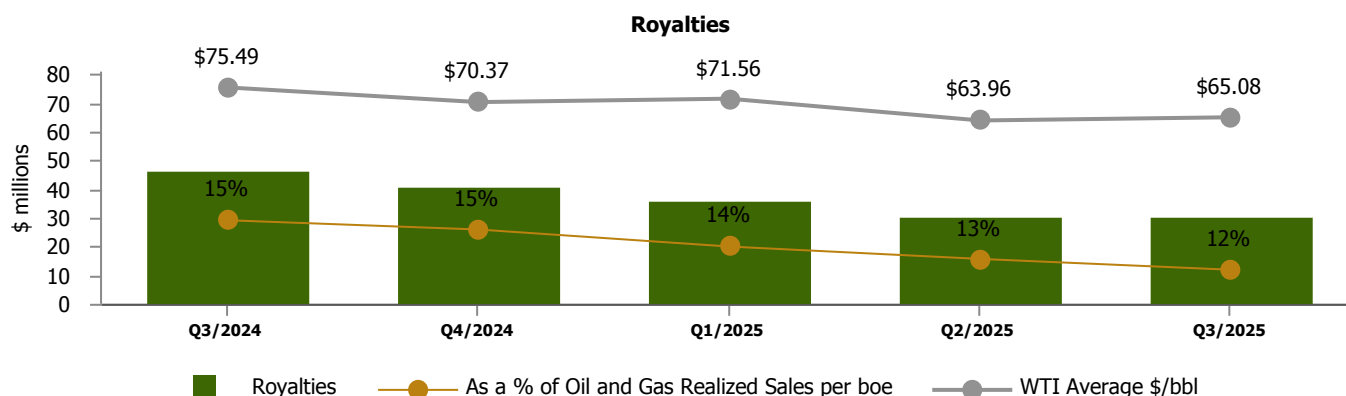
(3) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

For the three and nine months ended September 30, 2025 royalties as a percentage of sales were 12% and 13% compared to 15% and 16% for the three and nine months ended September 30, 2024. Second quarter 2025 royalties as a percentage of sales were 13%. The decrease in royalties as a percentage of sales from the 2024 comparative periods was primarily attributable to lower production and a decrease in world oil prices in 2025. Royalties decreased in areas where high price share royalties are applicable as a result of lower production and Benchmark WTI prices.

The decrease in royalty expense to \$30.8 million and \$98.1 million in the three and nine months ended September 30, 2025 compared to \$46.5 million and \$160.3 million for the 2024 comparative periods was mainly a result of lower production and a decrease in world oil prices in 2025. Royalties decreased in areas where high price share royalties are applicable as a result of lower production and Benchmark WTI prices.

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 nine months ended September 30, 2025 were \$65.08 and \$66.82 compared to \$75.49 and \$79.62 for the 2024 comparative periods and \$63.96 in the second quarter of 2025.

For further information concerning the HPR please refer to the Company's AIF, which may be accessed through the SEDAR+ website at www.sedarplus.ca.



Production Expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Production expense (\$000s)	\$ 62,120	\$ 65,005	\$ 168,470	\$ 187,570
Per unit (\$/boe) ⁽¹⁾	15.36	14.81	14.17	13.43

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

A breakdown of the production expense on a per boe basis between operated and non-operated fields are provided below:

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Per unit (\$/boe) – based on sales volumes – operated ⁽¹⁾	14.02	18.19	13.98	15.73
Per unit (\$/boe) – based on sales volumes – non-operated ⁽¹⁾	16.96	11.79	14.32	11.39

(1) Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

The following table presents the adjusted non-operated production expense per boe related to the one-time non-recurring adjustment to reflect a true-up to actual costs incurred to date for non-operated activities.

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Per unit (\$/boe) – based on sales volumes – non-operated ⁽¹⁾	16.96	11.79	14.32	11.39
Per unit (\$/boe) – non-recurring non-operated cost adjustment ⁽²⁾	(1.95)	—	(0.62)	—
Adjusted per unit (\$/boe) – based on sales volumes – non-operated ⁽¹⁾	15.01	11.79	13.70	11.39

(1) Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

(2) The non-recurring adjustment relates to prior periods and reflects a true-up to actual costs incurred to date for non-operated activities.

Production expense for the three and nine months ended September 30, 2025 was \$15.36/boe and \$14.17/boe compared to \$14.81/boe and \$13.43/boe for the three and nine months ended September 30, 2024. Production expense for the second quarter of 2025 was \$12.70/boe.

Operated properties production expense for the three and nine months ended September 30, 2025 was \$14.02/boe and \$13.98/boe compared to \$18.19/boe and \$15.73/boe for the three and nine months ended September 30, 2024. Operated properties production expense per boe has decreased for the nine months ended September 30, 2025 compared to the comparative 2024 period mainly as a result of increased production from development activities and the LLA-32 tuck-in acquisition resulting in decreased fixed cost absorption. During the second quarter of 2025 and continuing in the third quarter, corporate efficiency initiatives were implemented to reduce fixed and variable costs.

Non-operated properties production expense for the three and nine months ended September 30, 2025 was \$16.96/boe and \$14.32/boe compared to \$11.79/boe and \$11.39/boe for the three and nine months ended September 30, 2024. Non-operated properties production expense per boe has increased for the nine months ended September 30, 2025 compared to the comparative 2024 period mainly as a result of decreased production resulting in higher fixed cost absorption, the one-time non-recurring production cost adjustment that reflects a true-up to actual costs incurred to date for non-operated activities and increased electrical power costs, partially offset by lower well workovers and facility maintenance.

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

	Q3 2025 vs Q2 2025		Q3 2025 vs Q3 2024		YTD 2025 vs YTD 2024
Comparative period production expense per boe ⁽¹⁾	\$	12.70	\$	14.81	\$ 13.43
Power generation		1.24		1.12	0.95
Well workovers and facility maintenance		(0.17)		(1.54)	(0.44)
Colombian pesos ("COP") appreciation (depreciation)		0.52		0.34	(0.54)
Non-recurring non-operated production cost adjustment		0.89		0.89	0.30
Fixed costs absorption		0.08		0.18	0.66
Other variable costs		0.10		(0.44)	(0.19)
Current period production expense per boe⁽¹⁾	\$	15.36	\$	15.36	\$ 14.17

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

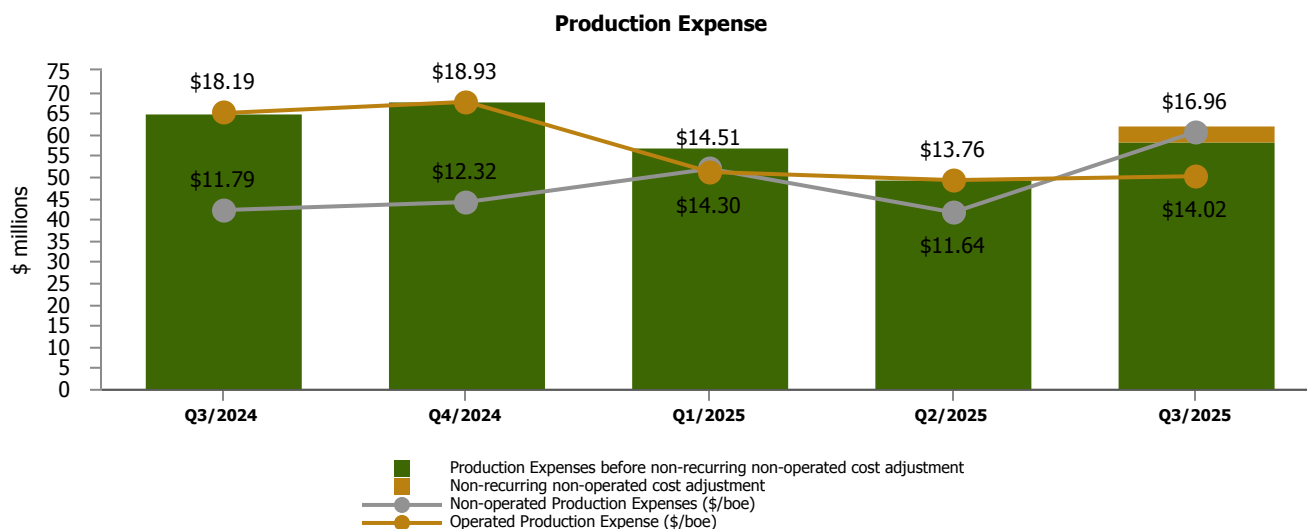
The increase in production expense per boe for the three months ended September 30, 2025 compared to the three months ended September 30, 2024 is mainly the result of increased cost of electrical power that supplies fields with required power to operate, one-time non-recurring non-operated production cost adjustment, higher fixed costs in 2025 being spread over lower production resulting in increased per boe costs and the appreciation of the COP, partially offset by lower well workovers and facility maintenance and other variable costs.

The increase in production expense per boe for the nine months ended September 30, 2025 compared to the nine months ended September 30, 2024 is mainly the result of increased cost of electrical power that supplies fields with required power to operate, one-time non-recurring non-operated production cost adjustment, higher fixed costs in 2025 being spread over lower production resulting in increased per boe costs, partially offset by lower well workovers and facility maintenance and the depreciation of the COP.

The increase in production expense per boe in the third quarter of 2025 compared to the second quarter of 2025 is primarily attributable to the increased cost of electrical power that supplies fields with required power to operate, one-time non-recurring non-operated production cost adjustment and the appreciation of the Colombian peso.

Colombia experienced an El Niño-induced drought that led to an escalation in power costs across the country during 2024. Colombia is heavily reliant on hydroelectric power. During the first quarter of 2025 power costs began to decrease due to more rainfall in the country, which replenished reservoirs used for hydroelectric power generation, causing power costs to decrease substantially in the second quarter. Costs began to increase during the third quarter of 2025, however have subsided in the fourth quarter to the present date.

With flush production coming from Blocks LLA-32 and LLA-74, the continued implementation of corporate efficiency initiatives, and power costs improving since late September, production expense per boe is estimated to be approximately \$12-13/boe in the fourth quarter of 2025.



Transportation Expense

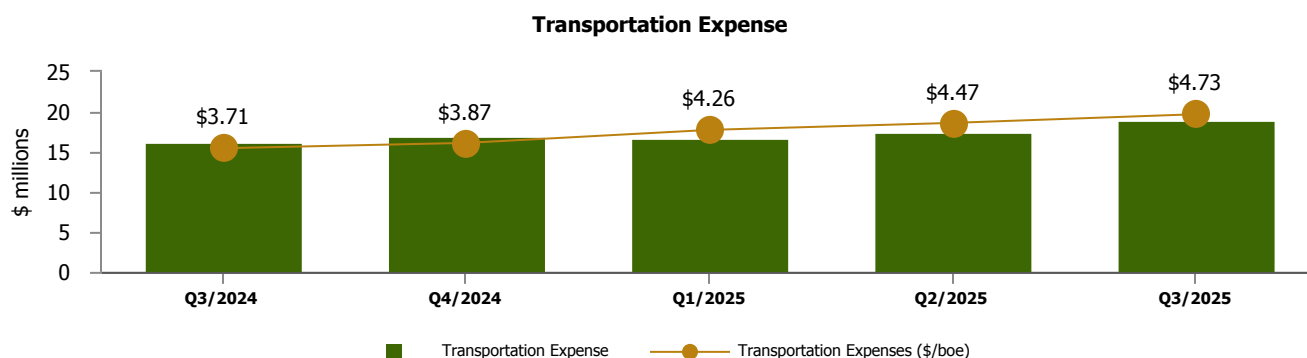
	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Transportation expense (\$000s)	\$ 19,124	\$ 16,299	\$ 53,363	\$ 48,868
Per unit (\$/boe) ⁽¹⁾	4.73	3.71	4.49	3.50

(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 nine months ended September 30, 2025 the cost of transportation on a per boe basis was \$4.73/boe and \$4.49/boe compared to \$4.47/boe in the second quarter of 2025 and \$3.71/boe and \$3.50/boe for the three and nine months ended September 30, 2024. Transportation expenses increased due to a higher volume of oil production being transported by truck and higher gas production from Capachos and VIM-1 Blocks compared to the comparative periods. The higher trucked oil volumes are associated with additional production from Azogue and new production from Block LLA-74.

The combined transportation expense and price differential from Brent, on a per boe basis, has decreased from the third quarter of 2024 and increased slightly from the second quarter of 2025. See "Crude Oil Reference and Realized Prices".



General and Administrative Expense ("G&A")

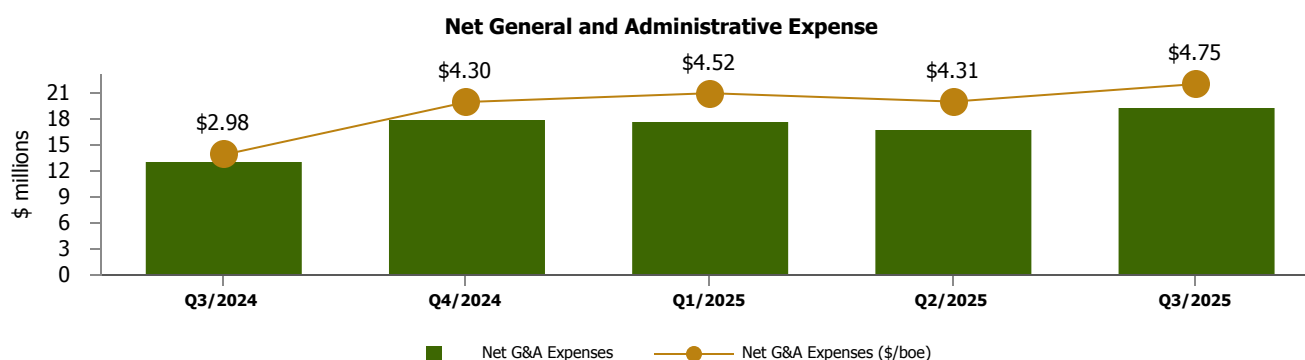
	For the three months ended September 30,		For the nine months ended September 30,	
(\$000s)	2025	2024	2025	2024
Gross G&A	\$ 22,408	\$ 16,472	\$ 64,132	\$ 59,638
G&A recoveries	(1,182)	(915)	(3,658)	(2,917)
Capitalized G&A	(2,012)	(2,524)	(6,805)	(5,713)
Total net G&A	\$ 19,214	\$ 13,033	\$ 53,669	\$ 51,008
Per unit (\$/boe) ⁽¹⁾	4.75	2.98	4.53	3.62

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

Net G&A was \$19.2 million and \$53.7 million for the three and nine months ended September 30, 2025 compared to \$13.0 million and \$51.0 million for the three and nine months ended September 30, 2024. Gross G&A was \$22.4 million and \$64.1 million for the three and nine months ended September 30, 2025 (three and nine months ended September 30, 2024 - \$16.5 million and \$59.6 million).

For the nine months ended September 30, 2025, on a per boe basis, net G&A has increased by 25% to \$4.53 from \$3.62 in comparative period of 2024. This is mainly due to lower production resulting in increased per boe costs.

The Company's G&A expense is denominated in local currencies of Colombian peso and Canadian dollars 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 September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Equity settled share-based compensation expense	\$ 169	\$ 229	\$ 531	\$ 655
Cash settled share-based compensation expense (recovery)	11,733	(8,223)	19,939	(5,342)
Total share-based compensation expense (recovery)	\$ 11,902	\$ (7,994)	\$ 20,470	\$ (4,687)

Share-based compensation expense was \$11.9 million and \$20.5 million for the three and nine months ended September 30, 2025 compared to a recovery of \$8.0 million and \$4.7 million for the three and nine months ended September 30, 2024.

Equity settled share-based compensation expense was \$0.2 million and \$0.5 million for the three and nine months ended 2025 compared to \$0.2 million and \$0.7 million for the three and nine months ended September 30, 2024. 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"). For the three and nine months ended September 30, 2025 there was an expense of \$11.7 million and \$19.9 million related to cash settled incentive plans compared to a recovery of \$8.2 million and \$5.3 million for the same periods in 2024. The increase in expense for the nine months ended September 30, 2025 is mainly attributable to additional units issued and appreciation in share price since granted. Parex's share price increased 30% during the period. The lower expense for the nine months ended September 30, 2024 is mainly attributable to the 52% 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 of the interim financial statements for the nine months ended September 30, 2025. As at September 30, 2025, the total cash settled incentive plans liability accrued was \$28.4 million (December 31, 2024 - \$19.9 million).

Cash payments to settle cash settled share-based compensation in the three and nine months ended September 30, 2025 were \$1.0 million and \$12.3 million compared to \$0.6 million and \$20.3 million for the same periods in 2024. The decrease in the nine months ended September 30, 2025 compared to the 2024 comparative period is mainly related to the decrease in Parex's share price at the time of settlement and a decrease in the number of units settled.

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

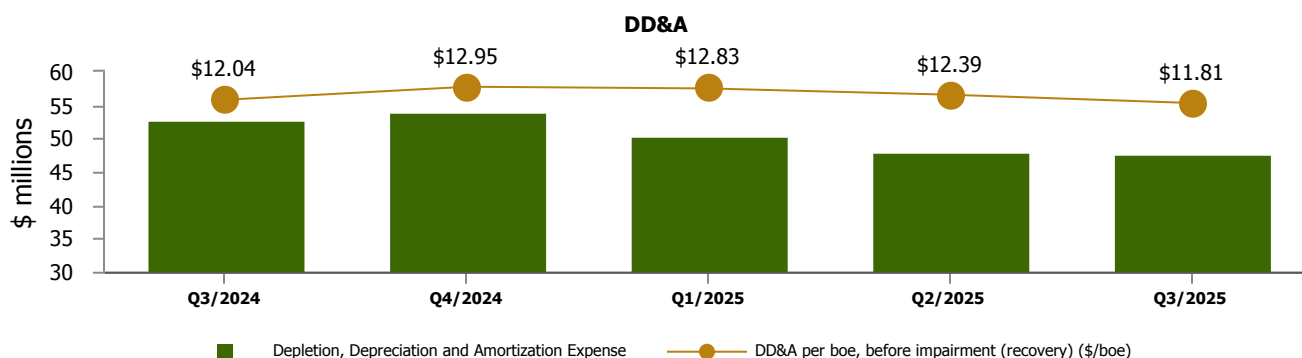
	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
DD&A expense (\$000s)	\$ 47,767	\$ 52,672	\$ 146,135	\$ 161,786
Per unit (\$/boe) ⁽¹⁾	11.81	12.04	12.34	11.47

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

Third quarter 2025 DD&A was \$47.8 million (\$11.81/boe) compared to \$52.7 million (\$12.04/boe) for the same period in 2024.

For the nine months ended September 30, 2025 future development costs of \$346.4 million (nine months ended September 30, 2024 - \$436.1 million) were included in the depletion calculation.

Third quarter 2025 DD&A of \$11.81/boe has decreased from the second quarter of 2025 of \$12.39/boe and the comparative period in 2024 of \$12.04/boe due to a lower depletion rate associated with reduced production, partially offset by adding to the depletable base through capital expenditures made during 2024 and the transfer of Arauca.



Foreign Exchange

	For the three months ended September 30,		For the nine months ended September 30,	
(\$000s)	2025	2024	2025	2024
Foreign exchange (gain) loss	\$ (2,709)	\$ 3,307	\$ (973)	\$ 3,253
Foreign currency risk management contracts (gain)	(2,513)	—	(7,870)	—
Total foreign exchange (gain) loss	\$ (5,222)	\$ 3,307	\$ (8,843)	\$ 3,253
Average foreign exchange rates				
USD\$/Cdn\$	1.38	1.36	1.40	1.36
USD\$/COP	4,004	4,094	4,132	3,979

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 USD. The Company has exposure in Colombia and Canada on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The main drivers of foreign exchange gains and losses recorded on the consolidated statements of comprehensive income are the COP denominated income tax payable and tax withholdings receivable, accounts payable and accounts receivable. The timing of payment settlements, accruals and their adjustments have impacts on foreign exchange gains/losses.

For the three and nine months ended September 30, 2025, total foreign exchange gain of \$5.2 million and \$8.8 million were recorded compared to losses of \$3.3 million in the three and nine months ended September 30, 2024.

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

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

Foreign Exchange Sensitivity Analysis

\$/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%	\$ 1.38	\$ (1.38)
Transportation expense	50%	\$ 0.24	\$ (0.24)
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 Q3 2025 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 September 30, 2025, 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 \$8.7 million.

Net Finance Expense

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Bank charges and credit facility fees	\$ 1,646	\$ 1,148	\$ 3,837	\$ 2,549
Interest on bank debt	431	878	1,665	3,474
Accretion on decommissioning and environmental liabilities	111	2,527	6,649	7,358
Interest and other income	(1,306)	(963)	(3,215)	(3,317)
Right-of-use-asset interest	48	48	141	143
Expected credit loss provision (recovery)	3,451	(130)	3,302	(96)
Other	109	1,204	732	662
Net finance expense	\$ 4,490	\$ 4,712	\$ 13,111	\$ 10,773

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Non-cash finance expense	\$ 3,566	\$ 2,836	\$ 9,952	\$ 7,261
Cash finance expense	924	1,876	3,159	3,512
Net finance expense	\$ 4,490	\$ 4,712	\$ 13,111	\$ 10,773

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 (income) include the accretion on decommissioning and environmental liabilities, other 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 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 September 30, 2025, the Company had the following crude oil risk management contracts in place.

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Premium
October 1, 2025 to October 31, 2025	ICE Brent	11,250	\$60.00	\$65.00	\$1.17
November 1, 2025 to November 30, 2025	ICE Brent	11,250	\$60.00	\$65.00	\$1.17
December 1, 2025 to December 31, 2025	ICE Brent	11,250	\$60.00	\$65.00	\$1.17

The table below summarizes the loss on the commodity risk management contracts that were in place during the three and nine months ended September 30, 2025 and 2024:

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Realized gain on commodity risk management contracts	\$ —	\$ —	\$ (3,337)	\$ —
Premiums paid on commodity risk management contracts	3,193	—	6,723	—
Unrealized gain on commodity risk management contracts	(172)	—	(1,332)	—
Total	\$ 3,021	\$ —	\$ 2,054	\$ —

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 September 30, 2025, the Company had the following foreign currency risk management contracts in place.

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
September 15, 2025 to October 15, 2025	COP	Costless Collar	\$10,000,000	4,400-4,650
October 15, 2025 to November 18, 2025	COP	Costless Collar	\$10,000,000	4,400-4,650
November 18, 2025 to December 15, 2025	COP	Costless Collar	\$10,000,000	4,400-4,650

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three and nine months ended September 30, 2025 and 2024 which is recorded in the financial statement line item "Foreign exchange (gain) loss" in the consolidated statements of comprehensive income:

	For the three months ended September 30,		For the nine months ended September 30,	
(\$000s)	2025	2024	2025	2024
Realized gain on foreign currency risk management contracts	\$ (3,193)	\$ —	\$ (4,418)	\$ —
Unrealized (gain) loss on foreign currency risk management contracts	680	—	(3,452)	—
Total	\$ (2,513)	\$ —	\$ (7,870)	\$ —

Income Tax

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Current tax expense	\$ 11,135	\$ 9,272	\$ 32,267	\$ 96,018
Deferred tax (recovery) expense	(4,035)	33,495	(12,466)	153,454
Tax expense	\$ 7,100	\$ 42,767	\$ 19,801	\$ 249,472
Effective current tax rate on funds flow provided by operations before tax⁽¹⁾	10 %	6 %	9 %	17 %

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

Current tax expense for the three months ended September 30, 2025 was \$11.1 million compared to \$9.3 million in the three months ended September 30, 2024. For the nine months ended September 30, 2025 current tax expense was \$32.3 million compared to \$96.0 million in the comparative 2024 period.

The significant decrease in current tax expense for the nine months ended September 30, 2025 compared to the 2024 comparative period is the result of lower operating cash flows before tax and the Company not being subject to the Colombian surtax in the current periods (as a result of lower Brent oil prices) compared to a 10% surtax applicable in the comparative periods of 2024. Certain tax strategies that have been deployed over recent years have also reduced current tax expense.

Deferred tax recovery for the three months ended September 30, 2025 was \$4.0 million compared to an expense of \$33.5 million in the three months ended September 30, 2024. For the nine months ended September 30, 2025 deferred tax recovery was \$12.5 million compared to an expense of \$153.5 million in the nine months ended September 30, 2024.

The decrease in deferred tax expense from the 2024 comparative periods is mainly a result of the depreciation of the Colombian peso in 2024 followed by a period of peso appreciation in 2025 to date. The calculation of current and deferred income tax in Colombia is based on a number of variables which can cause swings in current and deferred income tax. These variables include, but are not limited to, the year-end producing reserves used in calculating depletion for tax purposes, the timing and number of dry hole write-offs permissible for Colombian tax purposes, and currency fluctuations.

2025 Current Tax Guidance

The table below reflects the expected effective current tax rate on funds flow provided by operations before tax in 2025:

Brent price assumption	\$65/bbl	\$70/bbl	\$75/bbl
Effective current tax rate on before tax funds flow provided by operations ⁽¹⁾	1-4%	5-10%	10-14%

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

Capital Expenditures

For the three months ended September 30, (\$000s)	Colombia		Canada		Total	
	2025	2024	2025	2024	2025	2024
Acquisition of unproved properties	\$ 3,920	\$ 424	\$ —	\$ —	\$ 3,920	\$ 424
Geological and geophysical	36	1,269	—	—	36	1,269
Drilling and completion	63,817	56,488	—	—	63,817	56,488
Well equipment and facilities	11,186	24,083	—	—	11,186	24,083
Other	687	—	315	103	1,002	103
Total capital expenditures⁽¹⁾	\$ 79,646	\$ 82,264	\$ 315	\$ 103	\$ 79,961	\$ 82,367

For the nine months ended September 30, (\$000s)	Colombia		Canada		Total	
	2025	2024	2025	2024	2025	2024
Acquisition of unproved properties	\$ 5,146	\$ 1,678	\$ —	\$ —	\$ 5,146	\$ 1,678
Geological and geophysical	9,001	3,131	—	—	9,001	3,131
Drilling and completion	185,926	210,573	—	—	185,926	210,573
Well equipment and facilities	24,406	49,737	—	—	24,406	49,737
Other	687	—	539	466	1,226	466
Total capital expenditures⁽¹⁾	\$ 225,166	\$ 265,119	\$ 539	\$ 466	\$ 225,705	\$ 265,585

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

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

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Block LLA-34	\$ 9,260	\$ 20,050	\$ 37,603	\$ 72,374
Southern Llanos Basin	60,751	26,955	157,065	82,444
Northern Llanos Basin	5,264	29,105	21,149	96,822
Putumayo Basin	844	—	3,233	—
Magdalena Basin	2,840	6,154	5,429	13,479
Canada and Colombia - Corporate	1,002	103	1,226	466
Total capital expenditures⁽¹⁾	\$ 79,961	\$ 82,367	\$ 225,705	\$ 265,585

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

During the nine months ended September 30, 2025 the Company incurred \$225.7 million of capital expenditures with 93% spent on drilling, completion, well equipment and facilities in Colombia. During the nine months ended September 30, 2024, the Company incurred \$265.6 million of capital expenditures with 98% spent on drilling, completion, well equipment and facilities in Colombia.

During the third quarter of 2025 the Company incurred capital expenditures of \$80.0 million with 94% spent on drilling, completion, well equipment and facilities in Colombia. During the third quarter of 2024 the Company incurred capital expenditures of \$82.4 million with 98% spent on drilling, completion and well equipment and facilities in Colombia.

During the nine months ended September 30, 2025 the Company's capital expenditures of \$225.7 million were self-funded from funds flow provided by operations of \$332.1 million.

Property Acquisition

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

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

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

Assets acquired and liabilities assumed

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

Consideration for the acquisition

Purchase price	\$	19,000
Purchase price adjustments		(3,032)
Net consideration	\$	15,968
Cash paid	\$	14,970
Working capital adjustments		998
Total consideration paid	\$	15,968

No working capital was included in the assets acquired.

The pro forma results for the period ended September 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	\$	760,892
Net revenue less direct costs or operating netback ⁽¹⁾	\$	440,210

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

The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. The consolidated statement of comprehensive income for the six months ended September 30, 2025 includes \$18.8 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the six months ended September 30, 2025 attributable to the assets acquired since the LLA-32 Acquisition is \$12.6 million. Net income for the six months ended September 30, 2025 attributable to the assets acquired since the LLA-32 Acquisition is considered impracticable to calculate.

Long-Term Inventory

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

Cost	
Balance at December 31, 2023	\$ 204,701
Additions	55,990
Transfers to E&E and PP&E assets	(40,028)
Transfer to production costs	(5,269)
Sale of inventory	(5,920)
Impairment	(10,000)
Balance at December 31, 2024	\$ 199,474
Additions	9,578
Transfers to E&E and PP&E assets	(16,782)
Transfer to production costs	(1,998)
Sale of inventory	(698)
Balance at September 30, 2025	\$ 189,574

The table below represents the other long-term inventory expenditures for the three and nine months ended September 30, 2025 and 2024:

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Additions	\$ 3,701	\$ 6,025	\$ 9,578	\$ 47,801
Transfers to D&P and E&E assets	(5,272)	(9,418)	(16,782)	(33,087)
Transfer to production costs	(14)	(1,143)	(1,998)	(3,627)
Sale of inventory	—	(1,782)	(698)	(3,745)
Total long-term inventory expenditures, net of transfers and sales	\$ (1,585)	\$ (6,318)	\$ (9,900)	\$ 7,342

Summary of Quarterly Results

Three months ended (\$000s) (except per share amounts)	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,525	10,498	10,650	9,550
Heavy Crude Oil (bbl/d)	32,026	31,047	32,207	34,882
Crude Oil (bbl/d)	42,551	41,545	42,857	44,432
Conventional Natural Gas (mcf/d)	8,412	5,982	4,806	5,190
Total (boe/d)	43,953	42,542	43,658	45,297
Realized sales price - oil (\$/bbl) ⁽⁶⁾	62.32	61.07	67.05	64.01
Financial (\$000s except per share amounts)				
Oil and natural gas sales	\$ 252,424	\$ 239,070	\$ 265,635	\$ 277,824
Funds flow provided by operations ⁽⁵⁾	\$ 105,298	\$ 104,821	\$ 121,944	\$ 141,201
Per share – basic ⁽²⁾⁽⁴⁾	1.09	1.08	1.24	1.43
Per share – diluted ⁽²⁾⁽⁴⁾	1.09	1.08	1.24	1.43
Net income (loss)	\$ 50,476	\$ 49,113	\$ 80,629	\$ (69,051)
Per share – basic ⁽⁴⁾	0.52	0.50	0.82	(0.70)
Per share – diluted ⁽⁴⁾	0.52	0.50	0.82	(0.70)
Dividends paid	\$ 26,892	\$ 27,561	\$ 26,365	\$ 26,658
Per share - Cdn\$ ⁽⁴⁾⁽⁶⁾	0.385	0.385	0.385	0.385
Capital Expenditures ⁽¹⁾	\$ 79,961	\$ 88,690	\$ 57,054	\$ 82,110
Long-term inventory expenditures	\$ (1,585)	\$ (3,667)	\$ (4,648)	\$ (2,569)
Total assets (end of period)	\$ 2,260,531	\$ 2,223,178	\$ 2,197,955	\$ 2,155,062
Outstanding shares (end of period) (000s)	96,564	97,184	97,814	98,339
Working capital (deficit) surplus (end of period) ⁽³⁾⁽⁵⁾	\$ (3,167)	\$ 20,048	\$ 69,040	\$ 59,397
Three months ended (\$000s) (except per share amounts)	Sep. 30, 2024	Jun. 30, 2024	Mar. 31, 2024	Dec. 31, 2023
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	9,064	9,541	7,237	9,700
Heavy Crude Oil (bbl/d)	37,777	43,229	45,543	46,760
Crude Oil (bbl/d)	46,841	52,770	52,780	56,460
Conventional Natural Gas (mcf/d)	4,368	4,788	3,348	5,214
Total (boe/d)	47,569	53,568	53,338	57,329
Realized sales price - oil (\$/bbl) ⁽⁶⁾	69.07	75.69	71.02	71.06
Financial (\$000s except per share amounts)				
Oil and natural gas sales	\$ 302,033	\$ 364,874	\$ 335,298	\$ 370,688
Funds flow provided by operations ⁽⁵⁾	\$ 151,773	\$ 180,952	\$ 148,307	\$ 193,377
Per share – basic ⁽²⁾⁽⁴⁾	1.50	1.77	1.43	1.85
Per share – diluted ⁽²⁾⁽⁴⁾	1.50	1.77	1.43	1.85
Net income	\$ 65,793	\$ 3,845	\$ 60,093	\$ 133,783
Per share – basic ⁽⁴⁾	0.65	0.04	0.58	1.28
Per share – diluted ⁽⁴⁾	0.65	0.04	0.58	1.28
Dividends paid	\$ 28,467	\$ 28,528	\$ 28,531	\$ 29,505
Per share - Cdn\$ ⁽⁴⁾⁽⁶⁾	0.385	0.385	0.375	0.375
Capital Expenditures ⁽¹⁾	\$ 82,367	\$ 97,797	\$ 85,421	\$ 91,419
Long-term inventory expenditures	\$ (6,318)	\$ 9,817	\$ 3,843	\$ (866)
Total assets (end of period)	\$ 2,290,683	\$ 2,324,483	\$ 2,355,512	\$ 2,415,327
Outstanding shares (end of period) (000s)	100,031	101,616	102,914	103,812
Working capital surplus (end of period) ⁽³⁾⁽⁵⁾	\$ 37,509	\$ 34,156	\$ 55,901	\$ 79,027

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

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

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

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

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

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

Factors that Caused Variations Quarter Over Quarter

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

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

Liquidity and Capital Resources

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

The Company can adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure, share buy-back and dividend programs to the extent the capital expenditures are not committed. The Company considers its capital structure currently to include shareholders' equity, the credit facility and its working capital. As at September 30, 2025, shareholders' equity was \$1,912.4 million (December 31, 2024 - \$1,831.3 million).

As at September 30, 2025, the Company had working capital deficit of \$3.2 million⁽¹⁾ as compared to working capital surplus of \$59.4 million⁽¹⁾ at December 31, 2024.

As at September 30, 2025, Parex held \$69.8 million of unrestricted cash compared to \$98.0 million at December 31, 2024. 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, 2024 - \$240.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash or letter of credit needs as they arise. As at September 30, 2025, \$10.0 million (December 31, 2024 - \$60.0 million) was drawn on the credit facility. The credit facility is secured by the Company's Colombian assets and has final maturity date of May 21, 2027. The next annual review is scheduled to occur in May 2026. Parex expects to draw on the credit facility at various times to manage timing differences associated with timing of vendor payments and oil sales collections. Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1. The Company is in compliance with all covenants.

Refer to note 23 - Commitments and Contingencies of the interim financial statements for the period ended September 30, 2025 for a description of the performance guarantees as well as the unsecured letters of credit.

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

Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at September 30, 2025 the Company had 96,564,136 common shares outstanding compared to 98,339,036 at December 31, 2024, a decrease of 1.8%. At November 3, 2025 the number of common shares outstanding has been reduced to 96,324,136 as a result of the Company's NCIB.

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 November 3, 2025 Parex has the following securities outstanding:

	Number	%
Common shares	96,324,136	99 %
Stock options	1,267,655	1 %
	97,591,791	100 %

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

Contractual Obligations, Commitments and Guarantees

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

In Colombia, the Company has provided guarantees to the ANH and Empresa Colombiana de Petróleos S.A., ("Ecopetrol") joint venture blocks related to the exploration work commitments on its Colombian concessions in the amount of \$223.4 million as at September 30, 2025 (December 31, 2024 - \$160.7 million). The guarantees have been provided in the form of letters of credit for varying terms that are mainly provided by select Latin American banks on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks.

At September 30, 2025, the total lease obligation was \$5.1 million (December 31, 2024 - \$5.2 million) of which \$4.3 million (December 31, 2024 - \$4.6 million) is classified as long-term in accordance with the lease term.

The following table summarizes the Company's estimated undiscounted commitments as at September 30, 2025:

(\$000s)	Total	<1 year	1 – 3 years	3 – 5 years	>5 years
Exploration	\$ 784,483	\$ 43,529	\$ 247,026	\$ 493,928	\$ —
Office and accommodations ⁽¹⁾	7,323	1,569	4,392	1,362	—
Decommissioning and Environmental Obligations	255,491	10,844	—	—	244,647
Total	\$ 1,047,297	\$ 55,942	\$ 251,418	\$ 495,290	\$ 244,647

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

Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2023	\$ 71,523	\$ 24,209	\$ 95,732
Additions	5,398	332	5,730
Settlements of obligations during the year	(7,038)	(3,235)	(10,273)
Loss on settlement of obligations	1,593	—	1,593
Accretion expense	6,853	2,353	9,206
Change in estimate - inflation and discount rates	(9,400)	(3,205)	(12,605)
Change in estimate - costs and timing of settlements	1,725	(8,342)	(6,617)
Foreign exchange gain	(2,185)	(2,906)	(5,091)
Balance, December 31, 2024	\$ 68,469	\$ 9,206	\$ 77,675
Additions	3,124	3,167	6,291
Property acquisitions - Note 10	702	118	820
Settlements of obligations during the period	(4,493)	(2,074)	(6,567)
Loss on settlement of obligations	539	—	539
Accretion expense	5,948	701	6,649
Change in estimate - inflation and discount rates	524	188	712
Change in estimate - costs and timing of settlements	1,329	790	2,119
Foreign exchange loss	2,290	1,332	3,622
Balance, September 30, 2025	\$ 78,432	\$ 13,428	\$ 91,860
Current obligation	(9,007)	(1,837)	(10,844)
Long-term obligation	\$ 69,425	\$ 11,591	\$ 81,016

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 September 30, 2025, 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 \$226.7 million as at September 30, 2025 (December 31, 2024 – \$216.8 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 11.1% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2024 – 11.2% 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 \$9.0 million (December 31, 2024 – \$11.7 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 \$28.8 million as at September 30, 2025 (December 31, 2024 – \$24.6 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 11.1% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2024 – 11.2% 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 \$1.8 million (December 31, 2024 – \$2.9 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 Event

On October 29, 2025, the Company announced that it has submitted a Proposal to the Board of Directors of GeoPark (NYSE: GPRK) to acquire all outstanding common shares of GeoPark for US\$9.00 per share in cash and has also acquired an 11.8% ownership position in GeoPark for a total cost of approximately \$40.5 million.

There can be no assurance that any transaction with GeoPark will be agreed to or completed. The foregoing should be read together with the Company's press release dated October 29, 2025, which includes important cautionary statements regarding forward-looking information, underlying assumptions and risk factors.

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", "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 significant return of capital through dividends, including its regular quarterly dividend, and share repurchases, while investing in the Company's assets to provide an appealing total shareholder return;
- Parex's expectations as to debt levels, commodity risk management and other hedging activities;
- Parex's 2025 guidance, including its anticipated capital expenditures; funds flow provided by operations and monthly, quarterly and annual average production;
- the Company's expectations and plans in respect of Q4 2025 average production and capital expenditures;
- Parex's expectations regarding an incremental growth in production arising from the LLA-32 and near-field exploration activities at LLA-74;
- Parex's expectation that crude oil inventory in future periods will be in line with normal historic levels;
- Parex's anticipated 2025 production expense per boe;
- Parex's expectations that its transportation expense will fluctuate period over period due to the mix of sales contracts types in force during the period;
- that Parex will review its exposure to foreign currency variations on an ongoing basis;
- Parex's foreign exchange sensitivity analysis;
- the terms and purpose of the Company's credit facility including the timing of the next annual review and borrowing base redetermination;
- the Company's plan to draw on the credit facility at various times to manage timing differences associated with the timing of vendor payments and oil sales collections;
- the Company's expectation that its available cash and cash equivalents, credit facilities, and expected funds flow provided by operations will be sufficient to support the growth of the Company and fund development activities;
- Parex's estimated undiscounted commitments, including exploration, office and accommodations and decommissioning and environmental obligations, and the anticipated timing thereof;
- the anticipated total undiscounted cash flows required to settle the Company's decommissioning and environmental liability cost, the anticipated timing thereof, and the internal resources available to the Company at the time of settlement;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy and the fluctuation of earnings based on strip prices;
- the 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 rate for 2025;
- 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; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industries; ability to access sufficient capital from internal and external sources; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; risk of failure to achieve the anticipated benefits associated with acquisitions; failure of counterparties to perform under the terms of their contracts; changes to pipeline capacity; the risk that Brent oil prices may be lower than anticipated; the risk that Parex's evaluation of its existing portfolio of development and exploration opportunities may not be consistent with its expectations; the risk that Parex may not have sufficient financial resources in the future to provide distributions to its shareholders; the risk that the Board may not declare dividends in the future and that there may not be base dividend growth or that Parex's dividend policy changes; the risk that Parex's risk management strategy may not be an effective means of managing and forecasting cash flow; the risk that Parex may not be responsive to changes in commodity prices; the risk that the Company's capital and operating expenditures relating to the protection of the environment may be greater than anticipated; the risk that Parex may not meet its production or capital expenditure guidance for the year ended December 31, 2025; the risk that the Company's environmental strategies may not be successful and that the Company may not remain in material compliance with environmental protection legislation; the risk that Parex may not deploy its long-lead inventory when anticipated; the risk that Parex may not be successful in attracting and retaining qualified successors to senior officers in the event of departure; the risk that the Company's inventory deployment in 2025 may be more or less than anticipated; 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, 2024 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; the anticipated benefits from the voluntary corporate restructuring; 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; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; on-stream timing of production from successful exploration wells; operational performance of non-operated producing fields; pipeline capacity; that Parex will have sufficient financial resources to pay dividends and acquire shares pursuant to its NCIB in the future; that strip prices will remain unchanged; and other matters. The ability of the Company to carry out its business plan is primarily dependent upon the continued support of its shareholders, the discovery of economically recoverable reserves and the ability of the Company to obtain financing or generate sufficient cash flow to develop such reserves.

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

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

This MD&A contains information that may be considered a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to: Parex's 2025 guidance, including its anticipated capital expenditures and funds flow provided by operations; Parex's anticipated 2025 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 2025; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will vary from the amounts set forth in this MD&A and such variations may be material. This information has been provided for illustration only and with respect to future periods is based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such financial outlook. The financial outlook contained in this MD&A was made as of the date of this MD&A and was provided for the purpose of providing further information about the Company's potential future business operations. Readers are cautioned that the financial outlook contained in this MD&A is not conclusive and is subject to change.

Distribution Advisory

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

Oil & Gas Matters Advisory

This MD&A contains a number of oil and gas metrics, including operating netbacks and FFO netbacks. These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods. 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.

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

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

Non-GAAP Financial Measures

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

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Property, plant and equipment expenditures	\$ 59,002	\$ 68,406	\$ 153,020	\$ 158,451
Exploration and evaluation expenditures	20,959	13,961	72,685	107,134
Capital expenditures	\$ 79,961	\$ 82,367	\$ 225,705	\$ 265,585

(\$000s)	For the three months ended					
	June 30, 2025	March 31, 2025	December 31, 2024	June 30, 2024	March 31, 2024	December 31, 2023
Property, plant and equipment expenditures	\$ 49,067	\$ 44,951	\$ 62,799	\$ 49,214	\$ 40,831	\$ 50,753
Exploration and evaluation expenditures	39,623	12,103	19,311	48,583	44,590	40,666
Capital expenditures	\$ 88,690	\$ 57,054	\$ 82,110	\$ 97,797	\$ 85,421	\$ 91,419

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

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Cash provided by operating activities	\$ 86,992	\$ 181,874	\$ 317,012	\$ 502,068
Net change in non-cash assets and liabilities	18,306	(30,101)	15,051	(21,036)
Funds flow provided by operations	105,298	151,773	332,063	481,032
Capital expenditures, excluding corporate acquisitions	79,961	82,367	225,705	265,585
Free funds flow	\$ 25,337	\$ 69,406	\$ 106,358	\$ 215,447

EBITDA, is a non-GAAP financial measure that is defined as net income adjusted for finance income and expenses, other expenses, 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, unrealized foreign exchange gains (losses), and unrealized gains (losses) on risk management contracts.

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

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Net income	\$ 50,476	\$ 65,793	\$ 180,218	\$ 129,731
Adjustments to reconcile net income to EBITDA:				
Finance income	(1,306)	(963)	(3,215)	(3,317)
Finance expense	5,796	5,675	16,326	14,090
Other expenses	3,815	1,819	17,415	4,019
Income tax expense	7,100	42,767	19,801	249,472
Depletion, depreciation and amortization	47,767	52,672	146,135	161,786
EBITDA	\$ 113,648	\$ 167,763	\$ 376,680	\$ 555,781
Non-cash impairment charges	—	—	—	4,661
Share-based compensation expense (recovery)	11,902	(7,994)	20,470	(4,687)
Unrealized foreign exchange (gain) loss	(4,245)	4,233	(11,534)	27,022
Unrealized gain on commodity risk management contracts	(172)	—	(1,332)	—
Adjusted EBITDA	\$ 121,133	\$ 164,002	\$ 384,284	\$ 582,777

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

Non-GAAP Ratios

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

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

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

Capital Management Measures

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

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Cash provided by operating activities	\$ 86,992	\$ 181,874	\$ 317,012	\$ 502,068
Net change in non-cash assets and liabilities	18,306	(30,101)	15,051	(21,036)
Funds flow provided by operations	\$ 105,298	\$ 151,773	\$ 332,063	\$ 481,032

(\$000s)	For the three months ended					
	June 30, 2025	March 31, 2025	December 31, 2024	June 30, 2024	March 31, 2024	December 31, 2023
Cash provided by operating activities	\$ 142,642	\$ 87,378	\$ 67,847	\$ 222,782	\$ 97,412	\$ 194,242
Net change in non-cash assets and liabilities	(37,821)	34,566	73,354	(41,830)	50,895	(865)
Funds flow provided by operations	\$ 104,821	\$ 121,944	\$ 141,201	\$ 180,952	\$ 148,307	\$ 193,377

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

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	2025	2024
Current Assets	\$ 224,109	\$ 248,208	\$ 224,109	\$ 248,208
Current Liabilities	227,276	210,699	227,276	210,699
Working capital (deficit) surplus	\$ (3,167)	\$ 37,509	\$ (3,167)	\$ 37,509

(\$000s)	For the three months ended					
	June 30, 2025	March 31, 2025	December 31, 2024	June 30, 2024	March 31, 2024	December 31, 2023
Current assets	\$ 239,485	\$ 259,256	\$ 245,943	\$ 281,846	\$ 276,113	\$ 337,175
Current liabilities	219,437	190,216	186,546	247,690	220,212	258,148
Working capital surplus	\$ 20,048	\$ 69,040	\$ 59,397	\$ 34,156	\$ 55,901	\$ 79,027

Supplementary Financial Measures

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Business Environment and Risks

Parex is exposed to various market and operational risks. For a discussion of these risks please refer to the "Risk Factors" section in Parex's AIF for the year ended December 31, 2024 as filed on SEDAR+ at www.sedarplus.ca or Parex's website at www.parexresources.com.

Internal Controls over Financial Reporting

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

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the nine months ended September 30, 2025 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 23 - 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, 2024.

Change in presentation

Prior period expense items have been reclassified to conform to the current period's presentation.

Loss (gain) on settlement of provisions, loss (gain) on disposition of tangible assets, and other municipal taxes, that were previously included in Finance expense, have been included in Other expenses:

Consolidated Statements of Comprehensive Income (unaudited)	For the three months ended September 30, 2024		For the nine months ended September 30, 2024	
Finance expense, as previously presented	\$	7,494	\$	18,109
Reclassification to Other expenses		(1,819)		(4,019)
Finance expense, as currently presented	\$	5,675	\$	14,090

DIRECTORS

Wayne Foo
Chairman of the Board

Lynn Azar

Alberto Consuegra

Sigmund Cornelius

Mona Jasinski

Jeff Lawson

G.R (Bob) MacDougall

Glenn McNamara
Lead Director

Imad Mohsen

Carmen Sylvain

OFFICERS & SENIOR EXECUTIVES

Imad Mohsen
President & Chief Executive Officer

Daniel Ferreira
President & Country Manager, Parex Resources Colombia

Cameron Grainger
Chief Financial Officer

Eric Furlan
Chief Operating Officer

Mike Kruchten
Sr. Vice President, Capital Markets & Corporate Planning

Joshua Share
Sr. Vice President, Corporate Services

Katie Bernard
Vice President, New Ventures

CORPORATE HEADQUARTERS

Parex Resources Inc.
2700, Eighth Avenue Place, West Tower
585 8 Avenue S.W.,
Calgary, Alberta, Canada T2P 1G1

Tel: 403-265-4800
Fax: 403-265-8216

OPERATING OFFICES

Parex Resources (Colombia) AG Sucursal
Calle 113 No. 7-21, Of. 611,
Edificio Teleport, Torre A
Bogotá, Colombia

Tel: +57 (601) 841-8457

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

**TRANSFER AGENT
AND REGISTRAR**

Odyssey Trust Company
Calgary, Alberta

RESERVES EVALUATORS

GLJ Ltd.
Calgary, Alberta

INVESTOR RELATIONS

Michael Kruchten
Sr. Vice President, Capital Markets & Corporate Planning

Tel: 403-517-1733

Steven Eirich
Sr. Investor Relations & Communications Advisor

Tel: 587-293-3286

E-mail: investor.relations@parexresources.com

Website: www.parexresources.com

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