MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2025 and 2024

PetroTal

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MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the operating results and financial condition of PetroTal Corp. ("PetroTal" or the "Company") for the years ended December 31, 2025 and 2024, is dated March 25, 2026, and should be read in conjunction with the Company's audited consolidated financial statements (the "Financial Statements") and the Company's Annual Information Form ("AIF") for the years ended December 31, 2025 and 2024. The audited Financial Statements were prepared by management in accordance with International Financial Reporting Standards ("IFRS®") issued by the International Accounting Standards Board ("IASB"), representing generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada.

Financial figures throughout this MD&A are stated in thousands of United States dollars ("$" or "USD") unless otherwise indicated. This MD&A contains forward-looking statements that should be read in conjunction with the Company's disclosure under "Forward-looking statements and business risks".

1. CORPORATE OVERVIEW

PetroTal Corp. and its subsidiaries (the "Company" or "PetroTal") are engaged in the exploration, appraisal, and development of oil in Peru, South America. PetroTal is a publicly-traded energy company, incorporated and domiciled in Canada, with management offices in Houston, Texas, and Lima, Peru. The Company's registered office is located at 4200 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada. PetroTal's common shares are listed on the Toronto Stock Exchange (TSX: TAL), AIM Market of the London Stock Exchange (AIM: PTAL), and OTCQX (PTALF). Through its Peruvian subsidiaries, the Company is actively developing hydrocarbons at Blocks 95 and 131 and holds exploration prospects and leads in Block 107.

2. PERFORMANCE HIGHLIGHTS

The Company reached several key operational and financial achievements as described below:

Operational Highlights

- Oil production was 7.1 million bbls, an average of 19,473 bopd in 2025, an increase of 9% from 6.5 million bbls, an average of 17,785 bopd in 2024. As of December 31, 2025 and 2024, the Company had 24 producing oil wells and 4 water disposal wells;
- Oil sales allocations were substantially all directed through two primary routes: 92.4% to exports through Brazil and 7.4% to the Iquitos refinery.
- PetroTal's 2025 annual independent reserves assessment, as prepared by Netherland Sewell and Associates, Inc. ("NSAI") shows the following values in major reserve categories, combining heavy plus light oil volumes:
    - Proved ("1P") reserve volumes of 66.2 million bbls, with a net present value discounted at 10% ("NPV-10") after tax of $0.7 billion;
    - Proved plus Probable ("2P") reserves of 110.4 million bbls, with an NPV-10 after tax valuation of $1.2 billion; and,
    - Proved plus Probable and Possible ("3P") reserves of 185.5 million bbls, with an NPV-10 after tax valuation of $1.8 billion.

Financial Highlights

- Revenue totaled $316.9 million in 2025, based on 7.0 million bbls sold, (average 19,212 bopd) at an average realized price of $45.19/bbl, compared to $373.9 million from 6.4 million bbls sold (average 17,785 bopd) at $58.19/bbl in 2024. Of the 316.9 million in revenue, $239.5 million corresponds to Bretana;
- Royalties paid to the Peruvian government in 2025 totaled $29.1 million ($4.15/bbl, 9.2% of revenues) compared to $29.5 million ($4.59/bbl, 7.9% of revenues) in 2024. Of the $29.1 million in royalties, $26.4 million is related to Bretana. Contributions to the 2.5% community social trust fund were $9.1 million in 2025, as compared to $10.4 million in 2024;
- Capital expenditures ("capex") were incurred totaling $75.6 million in 2025 compared to $172.1 million in 2024, primarily directed toward the drilling program, field infrastructure, and the expansion of fluid-handling facilities capacity in the Bretana field. The decrease in 2025 primarily reflects lower drilling activity relative to the prior year;
- EBITDA and free funds flow for 2025 were $160.7 million ($22.92/bbl) and $90.6 million ($12.93/bbl), respectively, compared to $227.9 million ($35.47/bbl) and $74.1 million ($11.54/bbl) in 2024, respectively;

- Net operating income totaled $203.3 million ($28.99/bbl) in 2025, compared to $274.3 million ($42.68/bbl) in 2024;
- Cash position at the end of 2025 was $139.1 million, including $112.4 million of unrestricted cash, compared to $114.5 million, including $102.8 million of unrestricted cash at the end of 2024;
- Restricted cash of $26.7 million at the end of 2025 was associated with the COFIDE and BanBif loan designated for use in the erosion control project compared to $11.7 million in 2024; and,
- The Company paid dividends of $41.3 million and repurchased 4.9 million shares for $2.5 million, before suspending its dividend policy in November 2025. In 2024 dividends of $60.5 million were paid and 8.8 million shares were repurchased for $4.9 million.

3. SELECTED FINANCIAL INFORMATION

3.1 FINANCIAL SUMMARY

		2025		Q4-2025		Q3-2025		Q2-2025		Q1-2025	
($ thousands)		$/bbl		$/bbl		$/bbl		$/bbl		$/bbl	
PRODUCTION:	Average production (bopd)		19,473		15,258		18,414		21,039		23,281
SALES:	Average sales (bopd)		19,212		15,059		18,028		20,578		23,286
	Total sales (bbls)		7,012,397		1,385,460		1,658,621		1,872,602		2,095,714
	Average Brent price	$ 67.21		$ 62.46		$ 66.96		$ 65.55		$ 73.96	
Weighted contracted sales price, gross		67.75		62.49		66.95		65.53		73.89	
LESS:	Tariffs, fees and differentials	(22.56)		(22.82)		(23.62)		(22.75)		(21.43)	
	Realized sales price, net	45.19		39.67		43.33		42.78		52.46	
REVENUES:	Oil revenue [1]	$ 45.19	$316,891	$ 39.67	$ 54,959	$ 43.33	$ 71,871	$ 42.78	$ 80,110	$ 52.46	$109,951
LESS:	Royalties [2]	5.45	38,237	6.32	8,759	4.80	7,961	4.95	9,276	5.84	12,241
	Operating expense (excluding erosion)	9.19	64,432	14.35	19,883	8.34	13,834	9.34	17,488	6.31	13,227
	Direct transportation:										
	Barging	0.69	4,819	0.48	670	0.60	1,003	0.79	1,482	0.79	1,664
	Dry Season Freight/ Storage/Inventory	0.87	6,086	0.22	301	2.76	4,579	0.30	570	0.30	636
	Total transportation	1.56	10,905	0.70	971	3.36	5,582	1.09	2,052	1.09	2,300
NET OPERATING INCOME ("NOI")		28.99	203,317	18.30	25,346	26.83	44,494	27.40	51,294	39.22	82,183
	NOI as % of Revenue		64 %		46 %		62 %		64 %		75 %
Erosion expense		1.87	13,085	2.95	4,083	3.91	6,481	0.38	705	0.87	1,816
General and administrative expense		4.21	29,502	3.52	4,877	4.38	7,271	4.15	7,775	4.57	9,579
Commodity price derivative loss (gain)		1.43	10,005	4.95	6,853	1.26	2,082	(0.19)	(361)	0.68	1,431
Net financial expenses		1.00	6,999	1.71	2,369	1.08	1,789	0.29	535	1.10	2,306
Income tax expense (recovery)		2.62	18,390	(2.71)	(3,753)	2.45	4,069	1.92	3,595	6.91	14,479
Depletion, depreciation and amortization expense		11.83	82,965	14.15	19,607	11.56	19,168	11.78	22,053	10.56	22,137
Foreign exchange (gain) loss		(0.26)	(1,816)	(0.66)	(913)	0.02	35	(0.28)	(521)	(0.20)	(417)
NET INCOME (LOSS)			44,187		(7,777)		3,599		17,513		30,852
FREE FUNDS FLOW			$ 90,431	$2.35	$ 3,257	$7.17	$ 11,886	$14.55	$ 27,246	$22.92	$ 48,042

[1] Tariff and marketing fees are expenses usually recorded by reducing revenues in the Financial Statements.

[2] Royalties include 2.5% community social trust initiative.

		2024		Q4-2024		Q3-2024		Q2-2024		Q1-2024	
($ thousands)		$/bbl		$/bbl		$/bbl		$/bbl		$/bbl	
PRODUCTION:	Average production (bopd)		17,785		19,142		15,203		18,290		18,518
SALES:	Average sales (bopd)		17,558		19,087		14,760		18,050		18,347
	Total sales (bbls)		6,426,106		1,756,030		1,357,961		1,642,578		1,669,537
	Average Brent price	$ 78.98		$ 73.42		$ 77.74		$ 83.87		$ 81.01	
Weighted contracted sales price, gross		79.15		73.16		78.58		83.92		81.14	
LESS:	Tariffs, fees and differentials	(20.96)		(21.10)		(20.52)		(21.15)		(20.89)	
	Realized sales price, net	58.19		52.06		58.06		62.76		60.25	
REVENUES:	Oil revenue [1]	$ 58.19	$373,940	$ 52.06	$ 91,421	$ 58.06	$ 78,850	$ 62.76	$103,086	$ 60.25	$100,583
LESS:	Royalties[2]	6.22	39,947	7.42	13,022	5.47	7,433	6.08	9,991	5.69	9,500
	Operating expense (excluding erosion)	6.90	44,320	7.88	13,843	8.23	11,176	6.10	10,023	5.56	9,278
	Direct transportation:										
	Diluent	0.77	4,931	0.14	248	0.90	1,218	1.16	1,898	0.94	1,567
	Barging	0.96	6,200	1.94	3,398	0.81	1,100	0.69	1,137	0.65	1,085
	Diesel	0.08	520	—	—	—	—	—	—	—	—
	Dry Season Freight/ Storage/Inventory	0.58	3,697	1.97	3,452	0.51	690	0.01	12	(0.27)	(457)
	Total transportation	2.39	15,348	4.05	7,098	2.22	3,008	1.86	3,047	1.32	2,195
NET OPERATING INCOME (NOI)		42.68	274,325	32.71	57,458	42.14	57,233	48.72	80,025	47.68	79,610
	NOI as % of Revenue		73 %		63 %		73 %		78 %		79 %
Erosion expense		1.57	10,117	5.45	9,569	0.40	548	—	—	—	—
General and administrative expense		5.65	36,291	4.86	8,534	6.75	9,160	6.41	10,528	4.83	8,071
Commodity price derivative loss (gain)		1.62	10,424	(1.55)	(2,726)	15.82	21,481	2.01	3,306	(6.97)	(11,638)
Net financial expenses (income)		0.49	3,156	1.19	2,096	(0.23)	(311)	0.62	1,018	0.21	353
Income tax expense (recovery)		6.21	39,902	(0.12)	(209)	4.45	6,038	8.81	14,471	11.74	19,603
Depletion, depreciation and amortization		9.69	62,242	10.54	18,504	9.64	13,092	9.32	15,311	9.19	15,338
Foreign exchange loss (gain)		0.12	743	0.25	448	0.03	46	(0.01)	(14)	0.16	264
NET INCOME			111,450		21,242		7,179		35,405		47,619
FREE FUNDS FLOW			$ 74,145	($5.93)	$(10,422)	$4.81	$ 6,537	$22.12	$ 36,334	$24.97	$ 41,696

[1] Tariff and marketing fees are expenses usually recorded by reducing revenues in the Financial Statements.

[2] Royalties include 2.5% community social trust initiative.

Note: Free Funds Flow calculation methodology was changed in Q2 2024 and for prior periods to include adjustments for foreign exchange and share based compensation to better measure the Company's generated cash. Previously reported was Q1 2024: $52,561.

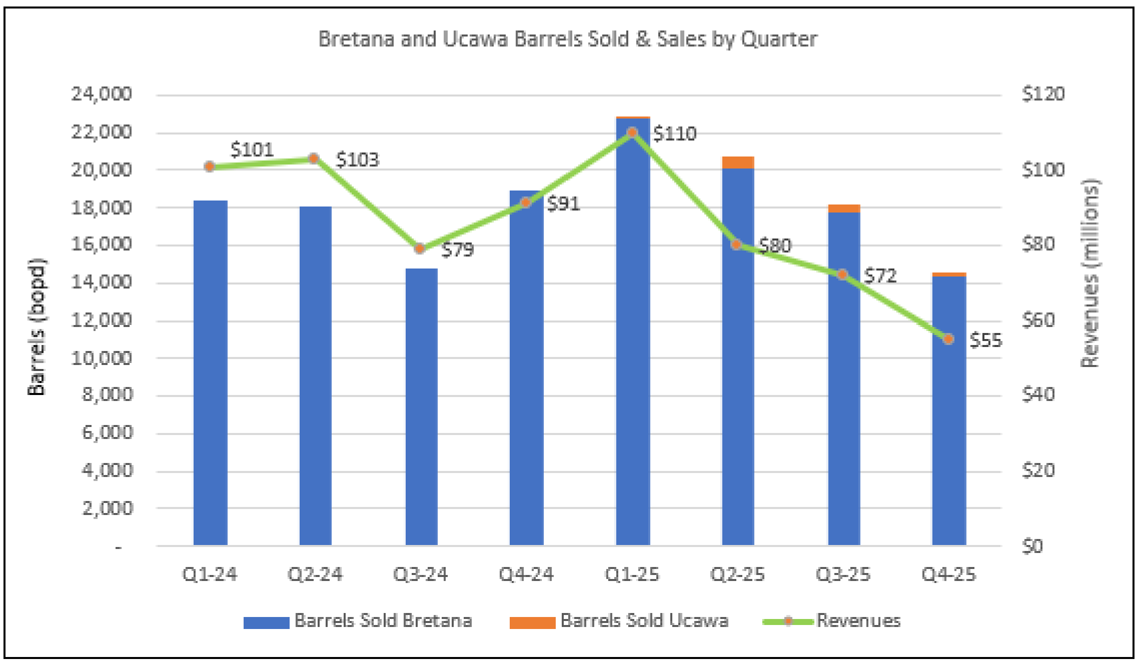
EARNINGS STATEMENT INFORMATION

Oil sales in 2025 increased by 9% to 7.0 million bbls (average 19,212 bopd), compared to 6.4 million bbls (average 17,785 bopd) in 2024. Sales decreased 21% to 1.4 million bbls (average 15,059 bopd) in Q4 2025 compared to 1.8 million bbls (average 19,087 bopd) in Q4 2024.

The Company may sell oil through three sales points: the local Iquitos refinery, exports through Brazil, and the ONP. In 2025, PetroTal sold substantially all of its oil through two primary routes: 92.4% to exports through Brazil and 7.4% to the Iquitos refinery. Sales via the ONP remained inactive during the period.

Pricing mechanisms differ by route. Sales to the Iquitos refinery were priced at the prevailing Brent oil price, less a quality differential discount and barge transportation charges. Oil exported through Brazil was sold on a freight on board ("FOB") Bretana basis, priced at the forecasted Brent oil price three months forward, less a fixed amount covering transportation, sales costs, and quality differential.

Sales to the ONP (Saramuro pump station) have been curtailed since February 2022, due to Petroperu's inability to fulfill the terms of the sales agreement. Under the agreement, sales to Petroperu at Saramuro for transportation through the ONP and onward to the Bayovar port are priced based on the eight-month forward forecasted Brent oil price, less a quality differential, and are net of all pipeline and marketing fees. When the oil is ultimately sold by Petroperu at Bayovar, PetroTal is subject to a valuation adjustment based on the actual price achieved, which may be higher or lower than the original forecasted price.



Royalties and social fund decreased to $38.2 million ($5.45/bbl) in 2025 from $39.9 million ($6.22/bbl) in 2024, and decreased to $8.8 million ($6.32/bbl) in Q4 2025 from $13.0 million ($7.42/bbl) in Q4 2024. Bretana oilfield royalties are calculated on production, net of transportation costs, starting at 5.0% for production up to 5,000 bopd and increasing linearly to 20.0% at 100,000 bopd or more. The Los Angeles oilfield royalties follows a similar structure, starting at 23.5% for production up to 5,000 bopd and scaling linearly to 38.5% at 100,000 bopd or more.

Operating expenses totaled $64.4 million ($9.19/bbl) in 2025, compared to $44.3 million ($6.90/bbl) in 2024, and $19.9 million ($14.35/bbl) in Q4 2025 compared to $13.8 million ($7.88/bbl) in Q4 2024. The increase in operating expenses during the year was mainly driven by higher pulling and well services, labor and completion activities, chemical consumption, warehouse management services, oil consumption, and supervision and maintenance services.

Erosion expenses in 2025 totaled $13.1 million ($1.87/bbl) compared to $10.1 million ($1.57/bbl) in 2024, and in Q4 2025 totaled $4.1 million ($2.95/bbl), reflecting lower spending on the Bretana infrastructure expansion, compared to $9.6 million ($5.45/bbl) in Q4 2024. The year-over-year increase was primarily driven by higher spending related to the Bretana infrastructure expansion, including the arrival of the main piling barge and initial fabricated steel components in mid-August, which enabled the commencement of piling work on the first breakwater.

Direct transportation expenses in 2025 totaled $10.9 million ($1.56/bbl) compared to $15.3 million ($2.39/bbl) in 2024 mainly due to discontinuation of the diluent purchase for blending. Q4 2025 totaled $1.0 million ($0.70/bbl), a decrease from $7.1 million ($4.05/bbl) in Q4 2024 mainly due to the elimination of diluent and lower barging costs.

General and administrative ("G&A") expenses in 2025 totaled $29.5 million $4.21/bbl) compared to $36.3 million ($5.65/bbl) in 2024, and in Q4 2025 totaled $4.9 million ($3.52/bbl), compared to $8.5 million ($4.86/bbl) in Q4 2024. The year-over-year decrease was driven mainly by reduced consulting and professional services and a decrease in community support.

Net finance expenses totaled $7.0 million ($1.00/bbl) in 2025 compared to $3.2 million ($0.49/bbl) in 2024. The increase during the year was primarily driven by higher lease interest associated with significant new and expanded equipment leases entered into in late 2024 and throughout 2025, including additional drilling equipment and power generation assets, increased loan interest, and higher accretion of decommissioning obligations as the liability balance grew, partially offset by interest income and a long-term receivable present value adjustment gain. In Q4 2025, net finance expenses were $2.4 million ($1.71/bbl) mainly related to lease interest, loan interest, accretion of decommissioning obligations, offset by interest income and the present value adjustment on long-term receivables, compared to $2.1 million ($1.19/bbl) in Q4 2024.

Commodity price derivative loss in 2025 was $10.0 million ($1.43/bbl) compared to ($1.62/bbl)in 2024, and in Q4 2025 was $6.9 million ($4.95/bbl), representing the combined net fair value change of outstanding embedded derivatives and hedging contracts, compared to $2.7 million gain ($1.55/bbl) in Q4 2024. Under the oil sales agreement with Petroperu for deliveries into the Northern Peruvian Pipeline, revenues are subject to oil price fluctuations between delivery and final sale by Petroperu at the Bayovar port, creating an embedded derivative exposure. The resulting gains or losses are non-cash and contingent upon the eventual sale of oil volumes. If oil prices increase prior to sale, the projected losses may decrease or reverse, potentially benefiting the Company's financial results.

Depletion, depreciation and amortization ("DD&A") expenses in 2025 was $83.0 million ($11.83/bbl) compared to $62.2 million ($9.69/bbl) in 2024, and in Q4 2025 was $19.6 million ($14.15/bbl), compared to $18.5 million ($10.54/bbl) in Q4 2024. The year-over-year increase was mainly due to higher estimated future development costs and slightly higher production in 2025. DD&A is calculated using the unit-of-production method based on capital invested, including estimated future development costs, over proved plus probable reserves.

Foreign exchange gain in 2025 was $1.8 million ($0.26/bbl) compared to $0.7 million loss ($0.12/bbl) in 2024, and in Q4 2025 was $0.9 million gain ($0.66)/bbl), compared to $0.4 million loss ($0.25/bbl) in Q4 2024, primarily due to fluctuations in currency positions and transactional exposures.

Income tax expenses in 2025 was $18.4 million ($2.62/bbl) compared to $39.9 million ($6.21/bbl) in 2024. In Q4 2025, income tax was a $3.8 million recovery ($2.71/bbl), compared to a $0.2 million recovery ($0.12/bbl) in Q4 2024. The decrease was primarily driven by lower taxable income resulting from reduced revenues and higher operating costs.

3.2 SELECTED BALANCE SHEET INFORMATION

Liquidity and capital resources

As of December 31, 2025, the Company held cash of $112.4 million and restricted cash of $26.7 million, totaling $139.1 million, compared to held cash of $102.8 million and restricted cash of $11.7 million, totaling $114.5 million as of December 31, 2024. Working capital was $115.1 million million as of December 31, 2025, compared to $91.0 million as of December 31, 2024, reflecting higher cash balances and lower current liabilities year over year.

Current restricted cash of $17.0 million is primarily related to funds designated for the erosion control project, the social fund, and letters of credit bank guarantees for Block 107 exploration wells. The $9.7 million of non-current restricted cash is related to permitted hedging programs and funds designated for the erosion control project.

The Company manages its liquidity by maintaining sufficient cash balances and access to potential funding sources to meet operational, capital, and financial obligations as they become due. The Company's primary sources of liquidity are cash generated from operations, existing cash balances, and potential access to debt facilities. Based on current commodity price assumptions and planned activities, management believes that cash flows from operations combined with existing cash on hand are sufficient to fund planned capital expenditures, working capital requirements, and other obligations for at least the next twelve months.

The Company's short-term liquidity requirements include funding ongoing development drilling activities, community and social commitments, regulatory obligations, operating expenses, and general and administrative costs. Longer-term liquidity requirements include funding for field development projects, potential exploration activities, abandonment and reclamation obligations, and future tax liabilities.

The Company is subject to financial covenants under its loan agreement, including a minimum liquidity ratio, a maximum liabilities-to-equity ratio, and a minimum debt service coverage ratio, with the schedule of debt maturities in Note 11, *Debt,* to the Financial Statements. Management retains flexibility to adjust the timing and scope of capital programs in response to changes in commodity prices or other external factors affecting cash flows.

Liquidity risks

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with its financial liabilities. The Company's liquidity risk is affected by current and future commodity prices. If required, the Company may consider additional short-term financing or issuing equity to meet its future obligations. Declines in future commodity prices could affect the Company's ability to fund ongoing operations. The current economic environment may have significant adverse impacts on the Company including, but not exclusively:

- material declines in revenue and cash flows due to lower commodity prices;
- declines in revenue and operating activities resulting from constrained capital programs and oil production;
- inability to access financing sources; and,
- increased risk of non-performance by the Company's customers and suppliers.

Estimates and judgments made by management in the preparation of the Financial Statements are subject to a certain degree of measurement uncertainty during this volatile period. Management actively monitors these risks through sensitivity analyses, scenario modeling (e.g. lower oil price cases), stress testing on operating margins, and regular updating of the capital program. The Company also seeks to maintain flexibility in its investment schedule, avoid overcommitment, and preserve a prudent liquidity buffer.

Capital expenditures and investments

	Year Ended December 31,	
	2025	2024
Drilling Program	$ 25,118	$ 103,870
Field Infrastructure	30,527	42,444
Fluid Handling Facilities ("CPF")	5,042	10,454
Erosion Costs	7,716	154
Block 95	1,929	1,119
Block 107	1,674	1,422
Other	3,251	1,108
Exploration & development expenditures	75,257	160,571
SAP Project	381	2,425
Asset acquisition	—	9,078
Total capital expenditures	$ 75,638	$ 172,074

PetroTal invested $75.3 million in petroleum capital expenditures in 2025, compared to $160.6 million in 2024. The decrease reflects reduced drilling activity during the year.

As of December 31, 2025, the Company had $11.4 million in exploration and evaluation assets related to Block 95 and Block 107, compared to $10.4 million as of December 31, 2024.

Share capital

Authorized share capital consists of an unlimited number of common shares without nominal or par value. Holders of common shares are entitled to one vote per share and to receive dividends as declared by the Board of Directors.

As of March 25, 2026, PetroTal has the following securities outstanding (in thousands):

Common shares	920,328	98%
Performance share units	15,908	2%
Total	936,236	100%

Dividends

During the years ended December 31, 2025 and 2024, the Company paid dividends to shareholders of $41.3 million and $60.5 million, respectively. The Company paid dividends per share in the amount of $0.015 during the first through third quarters of 2025.

Normal course issuer bid ("NCIB")

On June 3, 2025, the Company renewed the NCIB, which will end no later than June 2, 2026. The renewal allows the purchase of up to 45.8 million common shares, representing approximately 5.0% of its outstanding common shares as of December 31, 2025. Purchases are subject to a daily limit of 0.2 million shares, with one block purchase per calendar week allowed to exceed this limit. Common shares purchased under the NCIB are cancelled or for settlement of employee share-based awards.

During the years ended December 31, 2025 and 2024, the Company purchased 4.9 million and 8.8 million common shares under the NCIB for total consideration of $2.5 million and $4.9 million, respectively. The surplus between the total consideration and the carrying value of the shares repurchased was recorded against retained earnings.

Share based compensation

The Company has granted performance share units ("PSUs") to certain employees and DSUs to non-employee directors under the Company's share-based compensation plans.

PSUs vest either after three years or in equal annual installments over three years. PSUs may include dividend equivalent units ("DEUs") that are settled in common shares. The number of PSUs, including DEUs, that ultimately vest is determined based on the achievement of specified performance conditions. These conditions consist of KPIs approved annually by the Board of Directors and are based on internal operational, financial, and strategic performance objectives. These KPI factors are non-market conditions and, once established for the performance period, are not subject to subsequent market-based volatility. Share-based compensation expense is adjusted during the year to reflect the final number of awards expected to vest based on Board-approved performance outcomes, and the final number of shares follows the applicable vesting schedule.

DSUs are granted to non-employee directors under the Company's DSU plan. DSUs are fully vested upon grant and are redeemable upon a holder ceasing to be a director of the Company. DSUs may include DEUs that are settled in cash at the prevailing market price of the Company's common shares.

The following tables detail the PSU and DSU activity and outstanding balances as of December 31, 2025 and 2024:

	Performance Share Units	Deferred Share Units
Balance at January 1, 2024	20,801,920	3,792,494
Additions	8,930,275	2,044,369
Issued	(9,910,871)	—
Forfeited	(1,542,321)	—
Exercised/settled	—	(765,428)
Balance at December 31, 2024	18,279,003	5,071,435
Additions	13,583,304	2,322,526
Issued	(12,519,467)	—
Forfeited	(3,434,940)	—
Balance at December 31, 2025	15,907,900	7,393,961

The Company recognized $3.7 million and $3.2 million of share-based compensation expense during the years ended December 31, 2025 and 2024, respectively, which is included in general and administrative expenses in the Consolidated Statements of Earnings and Other Comprehensive Income.

3.3 NON-GAAP FINANCIAL MEASURES

Non-GAAP Terms

This report contains financial terms that are not considered measures under GAAP such as operating netback, revenue and transportation expense adjustment, and funds flow provided by operations that do not have any standardized meaning under GAAP and may not be comparable to similar measures presented by other companies. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures.

Operating netback

The Company considers operating netbacks to be a key measure that demonstrates the Company's profitability relative to current commodity prices. Netback is calculated by dividing net operating income by total revenue.

Revenue and transportation expense adjustment

Revenue and transportation expense adjustment is a non-GAAP measure that includes transportation tariff, marketing fee, barging and diluent expenses.

Funds flow information

Funds flow provided by operations ("FFO") is a non-GAAP measure that includes all cash generated from operating activities and changes in non-cash working capital. The Company considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate cash from its core operating activities.

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

		Three Months Ended December 31			Year Ended December 31		
		2025		2024		2025	2024
Cash flow from operating activities							
Net (loss) income	$	(7,777)	$	21,241	$	44,187	$ 111,450
Adjustments for:							
Depletion, depreciation and amortization		19,607		18,504		82,965	62,242
Accretion of decommissioning obligation		560		360		2,153	1,292
Share based compensation plan		650		823		3,729	1,528
Net finance expenses		1,990		2,047		5,804	3,577
Deferred income tax expense (recovery)		(6,359)		6,473		(18,568)	28,521
Commodity price unrealized derivatives (gain) loss		8,361		(2,724)		11,827	6,683
Funds flow provided by operations before non-cash working capital	$	17,032	$	46,724	$	132,097	$ 215,293
Changes in non-cash working capital:							
Trade and other receivables		840		(14,730)		30,813	(13,522)
Prepaid expenses		2,169		(306)		(2,412)	(9,043)
Inventory		(216)		9,877		1,063	(302)
Income tax payable		2,589		(6,642)		35,932	18,586
Trade and other payables		14		13,065		4,010	10,253
Commodity price realized derivatives gain		—		—		—	9,645
Cash paid for income taxes		(3,905)		(150)		(37,236)	(150)
Net cash provided by operating activities	$	18,522	$	47,838	$	164,267	$ 230,760
Cash flow from investing activities							
Exploration and evaluation asset additions	$	(353)	$	(402)	$	(1,004)	$ (1,434)
Property, plant and equipment additions		(14,933)		(50,187)		(74,634)	(161,393)
Asset acquisition		—		(1,700)		—	(1,700)
Non-cash changes in working capital		906		(8,998)		(40,308)	(1,788)
Net cash used in investing activities		(14,380)		(61,287)		(115,946)	(166,315)
Net cash provided by operating and investing activities	$	4,142	$	(13,449)	$	48,321	$ 64,445

CAPITAL MANAGEMENT MEASURES

Adjusted EBITDA

Adjusted EBITDA means earnings before interest, taxes, depreciation and amortization, derivatives, foreign exchange, adjusted for realized derivatives gain (loss) and share-based compensation.

	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Net (loss) income	$ (7,777)	$ 21,241	$ 44,187	$ 111,450
Adjustments to reconcile net income:				
Depletion, depreciation and amortization	19,607	18,505	82,965	62,242
Net finance expenses	2,369	2,096	6,999	3,156
Income tax expense	(3,753)	(209)	18,390	39,902
Commodity price derivatives loss (gain)	6,853	(2,726)	10,005	10,424
Foreign exchange (gain) loss	(913)	448	(1,816)	743
EBITDA (non-GAAP)	$ 16,386	$ 39,355	$ 160,730	$ 227,917
Commodity price derivatives realized gain	1,507	—	1,822	5,904
Share based compensation plan	650	812	3,729	3,151
Adjusted EBITDA (non-GAAP)	$ 18,543	$ 40,167	$ 166,281	$ 236,972
Capital expenditures	(15,286)	(50,589)	(75,638)	(162,827)
Free funds flow (non-GAAP)	$ 3,257	$ (10,422)	$ 90,643	$ 74,145

Free funds flow after investing activities is a non-GAAP measure, and the Company considers free funds flow or free cash flow to be a key measure as it demonstrates the Company's ability to fund a return of capital without accessing outside funds.

4. RESERVE REPORT

The following summary presents PetroTal's oil reserves as at December 31, 2025 for the Bretana and Los Angeles oil fields, as evaluated by NSAI, an independent qualified reserves evaluator. The reserve estimates have been prepared in accordance with the standards set forth in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and the reserve definitions contained in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") of the Canadian Securities Administrators.

Additional reserve information will be included in PetroTal's Annual Information Form ("AIF") for the year ended December 31, 2025, to be filed on SEDAR (www.sedarplus.ca) and on PetroTal's website.

Block 95 - Bretana Heavy Oil Field

Oil production at the Bretana field commenced in June 2018 through a long-term testing program. In May 2019, the Company received approval of the Environmental Impact Assessment ("EIA"), which authorized full field development and provided the required permits to execute PetroTal's development strategy at Bretana.

Bretana continues to represent the Company's primary reserve base, comprising the majority of proved, probable, and possible reserves as at December 31, 2025.

Block 131 - Los Angeles Light Oil Field

The Los Angeles oil field in Block 131 was discovered in 2013 by Ucawa Energy S.A.C. (formerly CEPSA Peruana S.A.C.). As of December 31, 2025, the field had produced approximately 8.1 million barrels of oil. Block 131 is governed by an exploration and production license agreement expiring in 2038, subject to a 23.48% royalty rate at production levels below 5,000 bopd, with a sliding scale above that threshold similar to Block 95.

All production is currently sold to Petroperu, Peru's state-owned oil company, at Pucallpa and transported by barge along the Ucayali River to the Iquitos refinery.

Summary of Oil Reserves and Net Present Values as of December 31, 2025:

Company Oil Reserves (bbls. in millions)	Heavy Oil		Light Oil		Future Net Revenue After Income Taxes Discounted at (in USD billions)				
	Gross	Net	Gross	Net	0%	5%	10%	15%	20%
Proved Developed Producing	36.8	36.8	0.3	0.3	$0.7	$0.5	$0.4	$0.4	$0.3
Proved Undeveloped	26.3	26.3	2.7	2.7	$0.6	$0.4	$0.3	$0.2	$0.1
Total Proved	63.1	63.1	3.0	3.0	$1.3	$0.9	$0.7	$0.6	$0.4
Probable	43.4	43.4	0.9	0.9	$1.3	$0.8	$0.5	$0.3	$0.2
Total Proved & Probable	106.5	106.5	3.9	3.9	$2.6	$1.7	$1.2	$0.9	$0.6
Possible	74.3	74.3	0.8	0.8	$2.7	$1.3	$0.7	$0.4	$0.2
Total Proved & Probable & Possible	180.8	180.8	4.7	4.7	$5.3	$3.0	$1.9	$1.3	$0.8

Summary of Pricing and Inflation Rate Assumptions - Forecast Prices and Costs (US$/bbl.)

Year-end Forecast	2026	2027	2028	2029	2030	2031
Brent Crude - December 31, 2025	$63.92	$69.13	$74.36	$76.10	$77.62	$79.17

Year-end Crude Oil Reserves (bbls. in millions)

Category	2025	2024	Change
Proved Developed Producing	37.1	45.5	(18.5%)
Proved Undeveloped	29.1	21.6	34.7%
Total Proved	66.2	67.1	(1.3%)
Probable	44.2	46.6	(5.2%)
Total Proved plus Probable	110.4	113.7	(2.9%)
Possible	75.1	99.6	(24.6%)
Total Proved plus Probable & Possible	185.5	213.3	(13.0%)

Year-end Net Present Value at 10% - After Income Tax ($ millions)

Category	2025	2024	Change
Proved Developed Producing	$439	$776	(43.4%)
Proved Undeveloped	$245	$353	(30.6%)
Total Proved	$684	$1,129	(39.4%)
Probable	$486	$592	(17.9%)
Total Proved plus Probable	$1,170	$1,721	(32.0%)
Possible	$669	$1,036	(35.4%)
Total Proved plus Probable & Possible	$1,839	$2,757	(33.3%)

Year-end Net Asset Value ("NAV") per Share - After Tax

	December 31, 2025		December 31, 2024	
Category	US$/sh	CAD$/sh	US$/sh	CAD$/sh
Proved	$0.75	$1.03	$1.24	$1.78
Proved plus Probable	$1.28	$1.75	$1.89	$2.71
Proved plus Probable & Possible	$2.01	$2.76	$3.02	$4.35

Reserve Life Index ("RLI")

Category	December 31, 2025
Proved	9.3 years
Proved plus Probable	15.5 years
Proved plus Probable & Possible	26.0 years

Future Development Costs

The following information sets forth development costs deducted in the estimation of PetroTal's future net revenue attributable to the reserve categories noted below:

Proved	$534 million
Proved plus Probable	$908 million
Proved plus Probable & Possible	$1,153 million

The future development costs are estimates of capital expenditures required in the future for PetroTal to convert the corresponding reserves to proved developed producing reserves. Future abandonment cost estimates are $74 million (1P), $88 million (2P), and $120 million (3P).

Bretana's reserve life index for 1P and 2P reserves is 9.3 years and 15.5 years, respectively. The cumulative capital invested combined with all future development and abandonment costs represents total finding and development costs of $12.06/bbl for 1P reserves, $10.64/bbl for 2P reserves and $6.23/bbl for 3P reserves.

In addition to ongoing development of the Bretana oilfield, there are other prospects and exploration opportunities.

5. CRITICAL ACCOUNTING POLICIES, JUDGMENTS AND ESTIMATES

MATERIAL ACCOUNTING POLICIES

Refer to Note 2, *Material Accounting Policies*, of the audited Financial Statements for a summary of significant accounting policies applied by the Company.

USES OF ACCOUNTING ASSUMPTIONS, ESTIMATES AND JUDGMENTS

The preparation of the Company's Financial Statements requires management to make judgments, assumptions, and estimates that affect the application of accounting policies and the reported amounts of assets, liabilities, income, and expenses. These estimates and assumptions are based on historical experience and other relevant factors; however, actual results may differ. Estimates and underlying assumptions are reviewed on an ongoing basis, and revisions are recognized in the period in which they become known or in future periods, as applicable.

Decommissioning Obligations

The Company recognizes decommissioning obligations related to the future dismantling, decommissioning, abandonment, site disturbance, and environmental remediation of its petroleum properties and supporting infrastructure. The ultimate costs and timing of these obligations are uncertain and may vary due to changes in regulatory requirements, technological developments, industry practices, and site-specific conditions. These obligations are measured using discounted cash flow techniques and are subject to significant judgment, including assumptions regarding future costs, inflation, and discount rates. Changes in these assumptions may result in material adjustments to the recorded liabilities and related assets.

Depletion and Reserves

Petroleum properties are depleted using the unit-of-production method over proved plus probable reserves, as determined annually by independent reserve engineers. The depletion calculation requires significant estimates related to reserve quantities, production profiles, and future development costs. Reserve estimates involve the interpretation of geological, technical, and economic data and are inherently uncertain. Revisions to reserves or changes in commodity prices, production rates, or cost assumptions are applied prospectively and may materially affect depletion expense, asset carrying values, and impairment assessments.

Recoverable amounts for impairment testing are generally determined based on the present value of future cash flows derived from proved plus probable reserves. Changes in reserve estimates or economic assumptions may result in the recognition or reversal of impairment losses.

Income Taxes

Significant judgment is required in assessing the recoverability of deferred tax assets, including whether sufficient future taxable income will be available to utilize tax deductions before expiry. The realization of deferred tax assets depends on future profitability, which is influenced by production performance, commodity prices, development activity, and operating costs. Income tax balances are also affected by changes in tax legislation, tax rates, and interpretations by tax authorities. Changes in these assumptions may materially impact income tax expense or recoveries.

Provisions, Commitments and Contingent Liabilities

Amounts recognized as provisions and those disclosed as commitments and contingent liabilities are based on management's best estimates considering contractual terms, legal and regulatory requirements, and available information at the reporting date. These estimates involve judgment and are subject to uncertainty, as actual outcomes may differ from expectations due to changes in circumstances or future events.

6. RELATED PARTY TRANSACTIONS

The Company did not enter into any related party transactions or off-balance sheet arrangements during the years ended December 31, 2025 and 2024. Key management personnel compensation, including directors, is as follows:

	Year Ended December 31	
	2025	2024
Salaries, incentives and short term benefits	$ 2,518	$ 2,021
Directors' fees	1,629	1,322
Share-based compensation	1,598	1,736
Total	$ 5,745	$ 5,079

The compensation, share-based awards, and non-equity incentive, paid or accrued to the Chief Executive Officer and Board of Directors members are as follows:

Name	Compensation Earned	Share-based awards	Non-Equity Incentive Plans	2025 Total	2024 Total
Manuel Pablo Zuniga-Pflucker[(1)]	$ 520,000	$ 1,272,000	$ 468,000	$ 2,260,000	$ 2,053,945
Mark McComiskey (Chair)	105,000	180,000	—	285,000	288,352
Gavin Wilson	75,000	100,000	—	175,000	176,979
Eleanor J. Barker	97,000	100,000	—	197,000	198,429
Roger M. Tucker[(2)]	—	—	—	—	119,070
Jon Harris	95,000	100,000	—	195,000	183,629
Felipe Arbelaez	85,000	100,000	—	185,000	180,227
Emily Morris	75,000	100,000	—	175,000	175,165
Denisse Abudinen[(3)]	51,233	68,311	—	119,544	—
Director Compensation	$ 1,103,233	$ 2,020,311	$ 468,000	$ 3,591,544	$ 3,375,796

(1) Mr. Zuniga-Pflucker does not receive compensation fees or share-based awards for his role as a Director.

(2) Director retired from the Board in August 2024.

(3) Director appointed to the Board in April 2025.

7. INTERNAL CONTROL

In accordance with National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), the Company's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR").

ICFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Financial Statements in accordance with IFRS Accounting Standards. The Company's ICFR includes policies and procedures that pertain to the maintenance of records that accurately reflect transactions and dispositions of assets, provide reasonable assurance that transactions are recorded as necessary to permit preparation of Financial Statements in accordance with IFRS, and ensure that receipts and expenditures are made in accordance with management authorization.

Management has evaluated the effectiveness of the Company's ICFR as at December 31, 2025 and concluded that the Company's ICFR were designed and operating effectively as at that date.

There were no changes in the Company's ICFR during the year ended December 31, 2025 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

DC&P are designed to provide reasonable assurance that material information required to be disclosed in the Company's filings is recorded, processed, summarized and reported within the time periods specified by securities legislation. Management evaluated the effectiveness of the Company's DC&P as at December 31, 2025 and concluded that they were effective.

Internal control systems, no matter how well designed, have inherent limitations and can provide only reasonable assurance regarding financial reporting and disclosure.

8. SUBSEQUENT EVENT

On January 20, 2026, PetroTal notified a Peruvian bank of its intention to terminate its lease agreement relating to the Amazonia-1 drilling rig. The Company is evaluating options to dispose of the drilling rig.

On March 24, 2026, PetroTal canceled its contract with the construction consortium in charge of the Erosion Control project.

9. FORWARD-LOOKING STATEMENTS AND BUSINESS RISKS

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A constitute forward-looking statements. These statements relate to future events or the Company's future performance, including, but not limited to: the Company's business strategy, objectives, focus, outlook, drilling, completions, workovers, expansion of infrastructure, exploration of undeveloped acreage, anticipated costs and results of such activities, environmental and social initiatives, expected production and revenue, oil production levels, the 2026 capital program and budget (including drilling plans), balance sheet strength, hedging programs, and future development and growth prospects. All statements other than statements of historical fact may be forward-looking statements. Statements relating to expected production, reserves, prospective resources, recovery, costs, and valuation are also deemed forward-looking, as they involve estimates and assumptions regarding the potential profitability of producing such reserves in the future. Forward-looking statements can often be identified by words such as "anticipate," "plan," "continue," "estimate," "expect," "may," "will," "project," "predict," "potential," "intend," "could," "might," "should," "believe," or similar expression.

Forward-looking statements are based on key expectations and assumptions, including, but not limited to: the ability of existing infrastructure to deliver production, anticipated capital expenditures, reservoir characteristics, recovery factors, exploration upside, prevailing commodity prices, actual prices received (including pursuant to hedging arrangements), availability and performance of drilling rigs, facilities, pipelines, other oilfield services, and skilled labor, royalty regimes, exchange rates, regulatory and licensing requirements, the accuracy of the Company's geological interpretations, receipt of required regulatory approvals, success of future drilling and development activities, performance of new wells, the Company's growth strategy, general economic conditions, and availability of required equipment and services.

Although the Company believes these expectations and assumptions are reasonable, undue reliance should not be placed on forward-looking statements because no assurance can be given that they will prove to be correct. Actual results may differ materially due to known and unknown risks, uncertainties, and other factors, including, but not limited to: operational risks in development, exploration, and production; delays or changes in exploration or development plans; uncertainties in reserve estimates; fluctuations in production, costs, and expenses; health, safety, and environmental risks; commodity price volatility; price differentials and actual prices received; exchange rate fluctuations; legal, political, and economic instability in Peru; access to transportation routes and markets; changes in legislation affecting the oil and gas industry; and other factors beyond the Company's control. Additional risk factors are detailed in the Company's AIF, available on SEDAR+ at www.sedarplus.ca.

Forward-looking statements speak only as of the date of this MD&A and are expressly qualified by this cautionary statement. Subject to applicable securities laws, the Company has no obligation to update these statements or to compare them to actual results or changes in expectations. Financial outlook information regarding prospective results, financial position, or cash flows is based on assumptions about future events and management's current assessment of relevant information. Readers are cautioned not to use such financial outlook information for purposes other than those disclosed herein.

Prospective resources represent estimated quantities of petroleum potentially recoverable from undiscovered accumulations using future development projects. Estimates of prospective resources in this MD&A are based on an independent assessment by NSAI, effective December 31, 2025, prepared in accordance with COGE and NI 51-101 standards. For updated information regarding the Company's prospective resources, please refer to the Company's website for the most recent press release.

ADDITIONAL INFORMATION

Additional information about PetroTal Corp. and its business activities, including PetroTal's audited Financial Statements for the years ended December 31, 2025 and 2024 are available on the Company's website at www.petrotal-corp.com, and at www.sedarplus.ca.

DIRECTORS

Mark McComiskey (1)(4)(5)
Chair of the Board

Denisse Abudinen Butto(3)(5)

Felipe Arbelaez (3)(4)

Eleanor Barker (4)(5)

Jon Harris (1)(2)(5)

Emily Morris(2)(5)

Gavin Wilson (1)(2)(3)

Manuel Pablo Zuniga-Pflucker (2)

OFFICERS AND SENIOR EXECUTIVES

Manuel Pablo Zuniga-Pflucker
President and Chief Executive Officer

Camilo McAllister
Executive VP and Chief Financial Officer

Jorge Osorio
Chief Operating Officer

Amaris Cardona
Chief People & Culture Officer

Emilio Acin-Daneri
VP Corporate Development

Camilo Obando
VP Finance

Raul Farfan
VP HSE & Sustainability

CORPORATE HEADQUARTERS

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Calgary, Alberta, Canada

OPERATING OFFICE

PetroTal Peru SRL
144 Dionisio Derteano, Suite 1200
San Isidro
Lima, Peru

STOCK EXCHANGES

TSX Exchange
Toronto, Ontario, Canada
TSX: TAL

AIM Stock Exchange
London, United Kingdom
AIM: PTAL

OTCQX Stock Exchange
New York, USA
OTCQX: PTALF

LEGAL COUNSEL

Stikeman Elliott LLP
Calgary, Alberta, Canada

AUDITORS

Deloitte LLP
Calgary, Alberta, Canada

NOMINATED & FINANCIAL ADVISER

Strand Hanson Limited
London, United Kingdom

JOINT BROKERS

Stifel Nicolaus Europe Limited
London, United Kingdom

Peel Hunt LLP
London, United Kingdom

RESERVES EVALUATORS

Netherland, Sewell & Associates, Inc.
Dallas, Texas, USA

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada
Calgary, Alberta, Canada
London, United Kingdom
Massachusetts, USA and New Jersey, USA

(1) Member of the Corporate Governance and Compensation Committee.
(2) Member of the Reserves Committee.
(3) Member of the HSE CSR Committee.
(4) Member of the Audit Committee.
(5) Member of the Technical Committee.

GLOSSARY / ABBREVIATIONS

1P	Proved
2P	Proved plus Probable
3P	Proved plus Probable and Possible
AIF	Annual Information Form
BanBif	Banco Interamericano de Finanzas
bbl(s)	Barrel(s)
bopd	Barrels of Oil per Day
Capex	Capital Expenditures
CGU	Cash Generating Unit
COGE	Canadian Oil and Gas Evaluation Handbook
COFIDE	Corporación Financiera de Desarrollo S.A.
CPF	Central Processing Facilities
CSR	Community, Social and Regulatory
DC&P	Disclosure Controls and Procedures
DD&A	Depletion, Depreciation and Amortization
DEUs	Dividend Equivalent Units
DSUs	Deferred Share Units
EBITDA	Earnings Before Interest, Taxes, Depreciation, and Amortization
E&E	Exploration and Evaluation
EIA	Environmental Impact Assessment
EPS	Earnings per Share
FOB	Freight on Board
FFO	Funds Flow Provided by Operations
FVOCI	Fair Value through Other Comprehensive Income
FVTPL	Fair Value through Profit or Loss
G&A	General and Administrative
GAAP	Generally Accepted Accounting Principles
IASB	International Accounting Standards Board
ICE	Intercontinental Exchange
ICFR	Internal Control Over Financial Reporting
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
MD&A	Management's Discussion and Analysis
mmboe	Million Barrels of Oil Equivalent
NAV	Net Asset Value
NCIB	Normal Course Issuer Bid
Netback	Benchmark to assess the profitability based on revenues less royalties, operating and transportation costs
NI 51-101	National Instruments - Standards of Disclosure for Oil and Gas Activities
NI 52-109	National Instruments - Certification of Disclosure in Issuers' Annual and Interim Filings
NOI	Net Operating Income
NOLs	Net Operating Losses
NPV-10	Net Present Value Discounted at 10%
NSAI	Netherland Sewell and Associates, Inc.
OCP	Ecuador Pipeline
ONP	Northern Peruvian Pipeline
OOIP	Original Oil in Place
PDP	Proved Developed Producing
PP&E	Property, Plant and Equipment
PSUs	Performance Share Units

RLI	Reserve Life Index
USD	United States Dollar ($)
VAT	Value Added Tax

CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2025 and 2024

PetroTal

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MANAGEMENT'S REPORT

The accompanying audited consolidated financial statements and all information in the management's discussion and analysis, and notes to the consolidated financial statements are the responsibility of management. The consolidated financial statements were prepared by management in accordance with IFRS® Accounting Standards as issued by the International Accounting Standards Board ("IASB") outlined in the notes to the consolidated financial statements. Other financial information appearing throughout the report is presented on a basis consistent with the consolidated financial statements.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded, and financial records properly maintained to provide reliable information for the presentation of consolidated financial statements.

The Audit Committee meets quarterly with management and the independent auditors to review auditing matters, financial reporting issues, and to satisfy itself that all parties are properly discharging their responsibilities. The Audit Committee also reviews the consolidated financial statements, the management's discussion and analysis of financial results, and the independent auditor's report. The Audit Committee reports its findings to the Board of Directors for its approval of the consolidated financial statements for issuance to the shareholders.

The consolidated financial statements have been audited, on behalf of the shareholders, by the Company's independent auditors, in accordance with Canadian generally accepted auditing standards. Independent auditor has full and free access to the Audit Committee.

Signed "Manuel Pablo Zuniga-Pflucker"
Manuel Pablo Zuniga-Pflucker
President and Chief Executive Officer

Signed "Camilo McAllister"
Camilo McAllister
Executive VP and Chief Financial Officer

March 25, 2026

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Calgary AB T2P 0R8
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Independent Auditor's Report

To the Shareholders and the Board of Directors of PetroTal Corp.

Opinion

We have audited the consolidated financial statements of PetroTal Corp. (the "Company"), which comprise the consolidated balance sheets as at December 31, 2025 and 2024, and the consolidated statements of earnings and other comprehensive income, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including material accounting policy information (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (“IASB”).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor’s Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2025. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Derivative Liabilities (embedded derivative) – Refer to Note 8 to the financial statements

Key Audit Matter Description

The Company has an agreement for the sale of crude oil with Petroleos del Peru (PetroPeru S.A. a state owned company based in Peru). Under the agreement, the Company has exposure to the volatility of oil commodity prices until the crude oil is finally sold by PetroPeru to its customers at the Bayovar terminal (i.e., final settlement date). The exposure to fluctuations of future commodity prices is an embedded derivative and is measured at fair value at the end of the reporting period. The fair value of the derivative is calculated using the future strip prices of Brent on the estimated final settlement dates for each shipment that has not reached Bayovar terminal.

Determining the fair value of the embedded derivative required management to make significant estimates and assumptions regarding future strip prices of Brent on the estimated final settlement dates. Auditing these estimates and assumptions required a high degree of auditor judgment in applying audit procedures and in evaluating the results of those procedures. This resulted in an increased extent of audit effort.

How the Key Audit Matter Was Addressed in the Audit

Our audit procedures related to the fair value determination of the embedded derivative included the following, among others:

- Evaluated management's ability to accurately estimate the final settlement dates by:
  - Comparing historical sales settlement dates with management's estimated final settlement dates;
  - Obtaining corroborating evidence to support management's estimate of the settlement date, as well as assessing whether there was any evidence contradicting management's estimates;
- Evaluated the reasonableness of the prices used in the determination of the fair value of the embedded derivative by independently assessing the price to future third-party strip prices of Brent, considering the estimated final settlement dates; and
- Recalculated the fair value of the embedded derivative and compared it to the fair value determined by management.

Property, Plant and Equipment – Petroleum interests – Refer to Note 10 to the financial statements

Key Audit Matter Description

The Company's property, plant and equipment includes petroleum interests. Petroleum interests are measured by depleting the assets on a unit-of-production method ("depletion") based on total estimated proved plus probable reserves. The Company engages independent reserve engineers to estimate the proved plus probable reserves using estimates, assumptions, and engineering data. The development of the Company's reserves used to evaluate depletion requires management to make significant estimates and assumptions related to future crude oil prices, reserves, and future operating and development costs.

Given the significant judgments made by management related to future crude oil prices, reserves, and future operating and development costs, these estimates and assumptions are subject to a high degree of estimation uncertainty. Auditing these estimates and assumptions required auditor judgment in applying audit procedures, including the extent of reliance on management's expert, and in evaluating the results of those procedures. This resulted in an increased extent of audit effort.

How the Key Audit Matter Was Addressed in the Audit

Our audit procedures related to future crude oil prices, reserves, and future operating and development costs used to determine depletion included the following, among others:

- Evaluated future crude oil prices by independently developing a reasonable range of forecasts based on reputable third-party forecasts and market data and comparing those to the future crude oil prices selected by management;
- Evaluated the Company's independent reserve engineers by examining reports and assessed their scope of work and findings; and assessing the competence, capability, and objectivity by evaluating their relevant professional qualifications and experience;

- Evaluated the reasonableness of reserves by testing the source financial information underlying the reserves and comparing the reserve volumes to historical production volumes;

- Evaluated the reasonableness of future operating and development costs by testing the source financial information underlying the estimate, comparing future operating and development costs to historical results, and evaluating whether they are consistent with evidence obtained in other areas of the audit.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the financial statements. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Christopher Gill.

/s/ Deloitte LLP
Chartered Professional Accountants Calgary, Alberta
March 25, 2026

CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. $)

As at	Note	December 31, 2025	December 31, 2024
ASSETS			
Current			
Cash	4	$ 112,400	$ 102,783
Restricted cash	4	17,039	5,745
Trade and other receivables	5	56,862	88,855
Inventory	6	12,233	13,570
Prepaid expenses	7	10,383	7,971
Derivative assets	8	967	1,307
Total current assets		209,884	220,231
Non-current			
Restricted cash	4	9,685	6,000
Trade and other receivables	5	24,307	21,608
Exploration and evaluation assets	9	11,410	10,406
Property, plant and equipment, net	10	541,781	537,018
Deferred income tax assets	18	1,077	1,963
Prepaid expenses	7	7,000	7,000
Derivative assets	8	—	311
Total non-current assets		595,260	584,306
Total assets		**$ 805,144**	**$ 804,537**
LIABILITIES and EQUITY			
Current			
Trade and other payables	12	$ 58,384	$ 94,955
Income tax payables	18	12,510	13,814
Lease liabilities	14	12,457	10,426
Short-term debt	11	11,408	10,047
Total current liabilities		94,759	129,242
Non-current			
Long-term debt	11	31,632	—
Long-term derivative liabilities	8	21,710	10,534
Lease liabilities	14	43,267	44,215
Decommissioning liabilities	13	42,768	34,383
Deferred income tax liabilities	18	53,093	72,548
Other long-term liabilities		2,649	2,107
Total non-current liabilities		195,119	163,787
Total liabilities		$ 289,878	$ 293,029
Equity			
Share capital	15	$ 138,228	$ 139,198
Contributed surplus		14,093	11,332
Retained earnings		362,945	360,978
Total equity		$ 515,266	$ 511,508
Total liabilities and equity		**$ 805,144**	**$ 804,537**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF EARNINGS AND OTHER COMPREHENSIVE INCOME

(In thousands of U.S. $, except per share amounts)

For the year ended December 31,	Note	2025	2024
REVENUES			
Oil revenues, net of royalties and social fund	16	$ 278,654	$ 333,993
Total revenue		278,654	333,993
EXPENSES			
Operating		64,432	44,320
Erosion		13,085	10,117
Direct transportation		10,905	15,348
General and administrative		29,502	36,291
Net finance expenses		6,999	3,156
Commodity price derivatives loss	8	10,005	10,424
Depletion, depreciation and amortization		82,965	62,242
Foreign exchange (gain) loss		(1,816)	743
Total expenses		216,077	182,641
Income before income taxes		**62,577**	**151,352**
Current income tax expense	18	36,958	11,381
Deferred income tax (recovery) expense	18	(18,568)	28,521
Net income and comprehensive income		**$ 44,187**	**$ 111,450**
Basic		$ 0.05	$ 0.12
Diluted		$ 0.05	$ 0.12
Weighted average common shares outstanding (in thousands):			
Basic		914,599	914,716
Diluted		933,568	935,686

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(In thousands of U.S. $, except per share amounts)

For the year ended December 31,	Note	2025	2024
Share capital			
Balance, beginning of year		$ 139,198	$ 140,672
Repurchase of shares	15	(970)	(1,474)
Balance, end of year		$ 138,228	$ 139,198
Contributed surplus			
Balance, beginning of year		$ 11,332	$ 9,853
Share based compensation plan	15	2,761	1,479
Balance, end of year		$ 14,093	$ 11,332
Retained earnings			
Balance, beginning of year		$ 360,978	$ 313,417
Dividends	15	(40,647)	(60,472)
Net income and comprehensive income		44,187	111,450
Repurchase of shares	15	(1,573)	(3,417)
Balance, end of year		$ 362,945	$ 360,978
Total equity		**$ 515,266**	**$ 511,508**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. $)

For the year ended December 31,	Note	2025	2024
Cash flows from operating activities			
Net income		$ 44,187	$ 111,450
Adjustments for:			
Depletion, depreciation and amortization		82,965	62,242
Accretion of decommissioning liabilities	13	2,153	1,292
Share based compensation plan		3,729	1,528
Commodity price unrealized derivatives loss	8	11,827	6,683
Net finance expenses		5,804	3,577
Deferred income tax (recovery) expense	18	(18,568)	28,521
Changes in working capital:			
Trade and other receivables		30,813	(13,522)
Prepaid expenses		(2,412)	(9,043)
Inventory		1,063	(302)
Trade and other payables		4,010	10,253
Commodity price realized derivatives loss	8	—	9,645
Income tax payables	18	35,932	18,586
Cash paid for income taxes		(37,236)	(150)
Net cash provided by operating activities		164,267	230,760
Cash flows from investing activities			
Property, plant and equipment additions	10	(74,634)	(161,393)
Exploration and evaluation asset additions	9	(1,004)	(1,434)
Asset acquisition	10	—	(1,700)
Non-cash changes in working capital		(40,308)	(1,788)
Net cash used in investing activities		(115,946)	(166,315)
Cash flows from financing activities			
Interest and fees paid		(2,573)	(34)
Repayment of debt principal		(16,277)	—
Funds received from credit facility	11	50,000	10,000
Debt issuance costs	11	(923)	—
Dividends paid		(41,348)	(60,472)
Repurchase of shares		(2,543)	(4,891)
Payment of current lease liabilities	14	(10,061)	(5,819)
Net cash used in financing activities		(23,725)	(61,216)
Increase in cash		24,596	3,229
Cash, beginning of year		102,783	90,568
(Increase) decrease in restricted cash	4	(14,979)	8,986
Cash, end of year		**$ 112,400**	**$ 102,783**

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2025 and 2024.
All amounts are stated in thousands of U.S. $, unless otherwise indicated.

1. CORPORATE INFORMATION

PetroTal Corp. and its subsidiaries (the "Company" or "PetroTal") are engaged in the exploration, appraisal and development of oil in Peru, South America. The Company is a publicly-traded energy company, incorporated and domiciled in Canada, with management offices in Houston, Texas, and Lima, Peru. The Company's registered office is located at 4200 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada.

These consolidated financial statements (the "Financial Statements") were approved for issuance by the Company's Board of Directors on March 25, 2026, based on the recommendation of the Audit Committee.

2. BASIS OF PREPARATION

STATEMENT OF COMPLIANCE

These Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS®" or "IFRS® Accounting Standards") as issued by the International Accounting Standards Board ("IASB").

In the preparation of these Financial Statements, certain balances as of December 31, 2024, have been reclassified to conform with the current period's presentation and to better reflect the nature of the underlying transactions:

- Value Added Taxes ("VAT") receivables ($23.0 million in current assets and $2.3 million in non-current assets): Balances as of December 31, 2024 were previously presented as a separate line item. In these Financial Statements, these amounts have been reclassified within the trade and other receivables line item (current and non-current assets).
- Prepaid expenses and others ($5.9 million in current assets): Balance as of December 31, 2024 related to prepayments made in Peru for current income tax purposes. As these amounts are applied against income tax payable for the respective period, they have been reclassified in these Financial Statements as a reduction to the income tax payables line item.

BASIS OF MEASUREMENT

These Financial Statements have been prepared on a going concern basis and on a historical cost basis except for certain financial instruments that have been measured at fair value.

PRINCIPLES OF CONSOLIDATION

The Financial Statements include the accounts of the Company and its subsidiaries. The Financial Statements of the subsidiaries are prepared for the same reporting period as the parent, using consistent accounting practices.

Intercompany balances and transactions, including any unrealized gains or losses arising from transactions with the Company's subsidiaries, are eliminated on consolidation.

USES OF ACCOUNTING ASSUMPTIONS, ESTIMATES AND JUDGMENTS

The preparation of the Company's Financial Statements requires management to make significant judgments, estimates, and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income, and expenses. These estimates and assumptions are based on historical experience and other relevant factors, and actual results may differ. Changes to estimates are recorded when they become known. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period of the revision if they affect only that period, or in both the period of the revision and future periods if they affect current and future periods. Significant estimates and judgments made by management in the preparation of these Financial Statements are outlined below.

Decommissioning Obligations

Decommissioning obligations are incurred by the Company at the end of the operating life of wells and supporting infrastructure. The Company is required to recognize a liability for future dismantling, decommissioning, abandonment, site disturbance, and environmental remediation costs associated with its petroleum properties in accordance with applicable laws, contracts, and other obligations. The ultimate costs and timing of these obligations are uncertain and may vary due to changes in legal and regulatory requirements, technological developments, industry practices, and experience at other production sites.

The estimated obligations are measured using a discounted cash flow approach with a risk-free discount rate and recorded as a long-term liability, with a corresponding increase to the carrying amount of the related long-lived asset, which is depleted on a unit-of-production basis over the life of the related reserves. The liability is adjusted each reporting period to reflect the passage of time, with accretion charged to net income, and for revisions to estimated future cash flows. Actual costs incurred upon settlement are charged against the liability. Significant judgment is required in estimating these obligations, and changes in assumptions, including inflation, may result in material adjustments that could impact future financial results.

Depletion and Reserves

When commercial production has commenced, petroleum properties are depleted using the unit-of-production method over proved plus probable reserves, as determined annually by qualified independent reserve engineers. For depletion purposes, capitalized petroleum property costs and related reserves are pooled at the cash-generating unit (“CGU”) level. The depletion base includes estimated future development costs necessary to bring proved plus probable reserves into production.

The calculation of depletion involves significant estimates, particularly regarding the quantity of reserves, the expected production profile, and future development costs. Changes in reserve estimates, commodity prices, production rates, or operating and development costs are accounted for prospectively and can materially affect depletion expense and the carrying value of petroleum properties.

Reserve estimates require management to interpret geological, technical, and economic data, which are inherently uncertain. These estimates directly impact the carrying value of petroleum properties, the calculation of depletion expense, and the recognition of potential impairments. Significant judgment is required in estimating reserves, and revisions, either upward or downward, could materially affect financial results, the timing and amount of depletion expense, and related financial statement disclosures.

For impairment testing, the recoverable amount of petroleum properties is generally determined with reference to the present value of future cash flows expected from production of proved plus probable reserves. Changes in reserve estimates or anticipated future production directly affect these recoverable amounts and may result in recognition or reversal of impairment losses.

Income Taxes

The estimation of income taxes requires significant judgment in assessing the recoverability of deferred tax assets, including whether it is probable that sufficient future taxable income will be available to utilize tax deductions before they expire. The realization of deferred tax assets depends on the generation of future taxable income, which is contingent upon the successful discovery, development, extraction, and commercialization of oil reserves. The measurement of deferred income taxes is subject to uncertainty related to the timing of future events and potential changes in tax legislation, tax rates, and interpretations by tax authorities. Changes in management's assessment of these factors may result in the recognition or reversal of deferred tax assets and could have a material impact on future income tax expense or recovery.

Provisions, Commitments and Contingent Liabilities

Amounts recognized as provisions and amounts disclosed as commitments and contingent liabilities are based on the terms of the related contracts, applicable laws and regulations, and management's best estimates at the time the Financial Statements are issued. These estimates require judgment and are subject to uncertainty, as actual outcomes may differ from expectations due to changes in circumstances or the occurrence of future events, which could result in material adjustments to the amounts recognized or disclosed.

MATERIAL ACCOUNTING POLICIES

Functional Currency

The functional currency of each of the Company's entities is the United States dollar, reflecting the currency of the primary economic environment in which each entity operates. The Financial Statements are presented in United States dollars. Foreign currency transactions are translated into the functional currency using exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses arising from the settlement of such transactions, as well as from the translation at period-end exchange rates of monetary assets and liabilities denominated in currencies other than an entity's functional currency, are recognized in the Consolidated Statements of Earnings and Other Comprehensive Income.

Cash and Restricted Cash

Cash includes deposits held with banks in the United States, Canada, and Peru that are available on demand and are highly liquid. Restricted cash represents amounts reserved for letters of credit to guarantee the Company's commitments related to exploration of Block 107, acquisition of qualified hydrocarbon assets, permitted hedging programs, and the 2.5% social development trust fund ("social fund") for the benefit of local communities. Restricted cash is not available for the Company's immediate or general business use.

Property, Plant and Equipment

Property, plant, and equipment ("PP&E") is recorded at cost less accumulated depreciation. Depreciation begins when an asset is available for use and is calculated using the straight-line method. Maintenance and repair costs are expensed as incurred, while costs of significant renewals and improvements that enhance the future economic benefits of an asset are capitalized. Gains or losses on disposal or retirement of PP&E are recognized in the Consolidated Statements of Earnings and Other Comprehensive Income.

When commercial production has commenced, petroleum properties are depleted using the unit-of-production method over proved plus probable reserves, as determined annually by qualified independent reserve engineers. For depletion purposes, capitalized petroleum property costs and related reserves are pooled at CGU level. The depletion base includes estimated future development costs necessary to bring proved plus probable reserves into production. Changes in estimates of reserves, future commodity prices, or operating and development costs that affect unit-of-production calculations are accounted for prospectively.

Other property and equipment, including buildings, furniture and fixtures, leasehold improvements, and information technology equipment, is recorded at cost less accumulated depreciation. These assets are generally depreciated on a straight-line basis over their estimated useful lives, which typically range from three to ten years. Leasehold improvements are amortized over the lesser of their estimated useful lives or the terms of the related lease agreements.

Exploration and Evaluation Assets

Exploration and evaluation (“E&E”) costs are expenditures incurred in connection with the exploration and evaluation of oil reserves for which technical feasibility and commercial viability have not yet been established. All costs directly attributable to exploration and evaluation activities are initially capitalized. These costs include acquisition of exploration rights, geological and geophysical costs, exploration drilling, sampling and appraisal activities, and directly attributable decommissioning costs. Costs incurred prior to obtaining the legal rights to explore an area are expensed as incurred.

E&E assets are not amortized during the exploration and evaluation phase. When technical feasibility and commercial viability are demonstrated, the accumulated E&E costs are transferred to petroleum properties and subsequently depleted using the unit-of-production method, with pooling applied at the CGU level as described above. When an area is determined not to be technically feasible and commercially viable, or when the Company decides to discontinue exploration activities in an area, the associated E&E costs are expensed and recognized as an impairment of exploration and evaluation assets in net earnings (loss).

Leases

The Company assesses each new contract to determine whether it contains a lease. A specific asset is the subject of a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The Company allocates contract consideration to the lease and non-lease components on the basis of their relative stand-alone prices.

The right-of-use asset is initially measured at cost, which includes: (i) the amount of the initial measurement of the lease liability, (ii) any lease payments made at or before the lease commencement date, less any lease incentives received, (iii) any initial direct costs incurred, and (iv) an estimate of restoration costs.

The lease liability and initial right-of-use asset are recognized at the lease commencement date, measured at the present value of fixed lease payments (including in-substance fixed payments) plus the exercise price of a purchase option if the lessee is reasonably certain to exercise that option, discounted at a rate the Company would be required to borrow over a similar term.

Key judgments include whether a contract identifies an asset (or a portion of an asset), whether the lessee obtains substantially all of the economic benefits of the asset over the contract term, whether the lessee has the right to direct the asset’s use, which components are fixed or variable in nature and the discount rate. The Company applied its incremental borrowing rate for leases where the implicit rate cannot be readily determined. Right-of-use assets are presented within property, plant and equipment.

After initial recognition, the lease liability is accreted for the passage of time and reduced for lease settlements made during each period. If the lease terms indicate that the Company will exercise a purchase option, the right-of-use asset is depreciated from the lease commencement date to the end of the useful life of the underlying asset. Otherwise, the right-of-use asset is depreciated to the earlier of the end of the useful life of the underlying asset or to the end of the lease term. Additionally, the Company remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:

(a) The lease term has changed or there is a significant event or change in circumstances resulting in a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

(b) The lease payments change due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which case the lease liability is remeasured by discounting the revised lease payments using an unchanged discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used).

(c) A lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured based on the lease term of the modified lease by discounting the revised lease payments using a revised discount rate at the effective date of the modification.

Impairment

Financial Assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, an impairment loss is recognized in net earnings (loss). Impairment losses are reversed in subsequent periods if the decrease in the impairment can be objectively related to an event occurring after the loss was recognized.

For financial assets measured at amortized cost, the impairment loss is calculated as the difference between the asset's carrying amount and the present value of the estimated future cash flows, discounted at the asset's original effective interest rate. Individually significant financial assets are assessed on an individual basis, while the remaining assets are assessed collectively in groups sharing similar credit risk characteristics.

Non-Financial Assets

At each reporting date, the Company reviews the carrying amounts of its non-financial assets to determine whether there is any indication of impairment. If such an indication exists, the recoverable amount of the asset or CGU is estimated and compared to its carrying amount. Assets are grouped into the smallest CGU that generates cash inflows that are largely independent of other assets or CGU.

The recoverable amount is the higher of fair value less costs to sell and value in use, with both determined by discounting estimated future cash flows using an after-tax discount rate that reflects current market assessments of the time value of money and asset-specific risks. An impairment loss is recognized in net earnings (loss) when the carrying amount of an asset or CGU exceeds its recoverable amount.

For petroleum properties, fair value less costs to sell and value in use are generally determined by reference to the present value of future cash flows expected from production of proved and probable reserves. E&E assets are tested for impairment upon transfer to petroleum properties and whenever facts and circumstances suggest the carrying amount may not be recoverable. Impairment indicators for E&E assets include:

- Expiry or impending expiry of lease with no expectation of renewal;
- Lack of budget or plans for substantive expenditures;
- Discontinuation of exploration activities due to a lack of commercially viable discoveries; and
- Situations where the carrying amount is unlikely to be recovered in full through a successful development.

Impairment losses recognized in prior years are assessed at each reporting date to determine whether there is an indication that the loss has decreased or no longer exists. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation or amortization, had no impairment loss been recognized.

Inventory

Inventory consists of crude oil and materials, parts, and supplies used in production, drilling, and maintenance activities and is measured at the lower of cost and net realizable value. Materials, parts, and supplies are generally expected to be consumed in the short term, and provisions are recorded for obsolete or slow-moving items when necessary.

Crude oil inventory consists of oil production held in tanks. The cost of crude oil inventory includes all costs incurred to bring the inventory to its storage location, including operating expenses, royalties, transportation, and depletion. Inventory costs are determined using the weighted average cost method and are recognized in earnings when the inventory is sold.

Financial Instruments

Financial instruments are recognized initially at fair value. Subsequent measurement depends on the classification of the financial instrument:

- Fair value through profit or loss ("FVTPL") – measured at fair value with changes recognized in net earnings (loss). Financial instruments classified as FVTPL include cash and cash equivalents and derivative commodity contracts.
- Fair value through other comprehensive income ("FVOCI") – measured at fair value, with changes recognized in other comprehensive income. Transaction costs are expensed as incurred. Financial instruments under this classification include derivative assets and liabilities where hedge accounting is applied.
- Amortized cost – measured at amortized cost using the effective interest rate method. Financial instruments classified at amortized cost include trade and other receivables, trade and other payables, accrued liabilities, and short- and long-term debt.

IFRS 9 includes a simplified hedge accounting model intended to align hedge accounting more closely with risk management activities. The Company does not use derivative instruments for trading or speculative purposes and does not designate derivative contracts as accounting hedges. Accordingly, all derivative instruments are classified as FVTPL and recorded on the Consolidated Balance Sheet at fair value, with changes in fair value recognized in net earnings (loss). Transaction costs attributable to derivative instruments are expensed as incurred. Fair values are determined using quoted market prices and/or third-party market data and forecasts.

Embedded derivatives are separated from host contracts and accounted for as derivatives when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, the embedded derivative meets the definition of a derivative, and the host contract is not measured at fair value through profit or loss. For the Petroperu contract, the value of the embedded derivative is driven by the expected delivery timing to the final point of sale, as the fair value depends on the oil price at the expected sale date.

The Company's financial instruments consist of cash, trade and other receivables, derivative assets, trade and other payables, derivative liabilities, and short- and long-term debt, all of which are included in the Consolidated Balance Sheet.

Decommissioning Obligations

The Company recognizes a decommissioning obligation for exploration and evaluation assets and for property, plant and equipment in the period in which a present obligation arises and a reasonable estimate of the fair value of the obligation can be made. Decommissioning obligations represent the estimated costs of dismantling, abandoning, restoring and remediating petroleum properties, facilities and pipelines arising from statutory, contractual, legal or constructive obligations.

Decommissioning obligations are initially measured at the present value of the estimated future expenditures required to settle the obligation, discounted using a risk-free discount rate. The estimates of future costs, timing of expenditures, discount rates and other assumptions, including climate-related considerations, are reviewed at each reporting date. Changes in the provision resulting from revisions to estimated cash flows or discount rates are accounted for prospectively by adjusting the carrying amount of the related asset and the corresponding decommissioning liability.

The unwinding of the discount on the decommissioning obligation is recognized as accretion expense in net earnings (loss). Actual costs incurred upon settlement of the obligation are charged against the provision. Any difference between the recorded provision and the actual costs incurred is recognized in net earnings (loss) in the period of settlement.

Erosion Costs

Erosion control costs are incurred to protect the Company's producing fields and surrounding communities from river-related erosion risks. These costs are capitalized when they result in future economic benefits to the Company, such as the protection or extension of the useful life of existing assets. Erosion control costs that primarily benefit the community or do not provide a direct future economic benefit to the Company are expensed as incurred.

Erosion costs are presented as a separate line item in the Consolidated Statements of Earnings and Other Comprehensive Income to enhance transparency and reliability of measurement. The related notes to the Financial Statements describe the nature of erosion activities, the accounting treatment applied, and the basis for distinguishing between capitalized and expensed costs.

Finance Income and Expenses

Net finance income or expense is comprised of interest income, including the unwinding of discount and present value adjustments on long-term receivables, interest expense on borrowings and lease liabilities, amortization of upfront financing fees, and accretion of the discount on decommissioning obligations. Net finance income or expense is recognized in the Consolidated Statements of Earnings and Other Comprehensive Income as incurred.

Income Taxes

Income tax expense comprises current and deferred income taxes. Current and deferred income taxes are recognized in net earnings (loss) except to the extent that they relate to a business combination or to items recognized directly in equity or in other comprehensive income (loss).

Current income tax represents the estimated income taxes payable or recoverable in respect of taxable income or loss for the current year, including adjustments to income taxes payable or recoverable in respect of prior years. Current income taxes are measured using tax rates and tax laws that have been enacted or substantively enacted at the reporting date.

Deferred income tax assets and liabilities are recognized for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and their corresponding tax bases, except for temporary differences arising on the initial recognition of goodwill, and for temporary differences arising on the initial recognition of assets or liabilities in transactions that are not business combinations and that, at the time of the transaction, affect neither accounting nor taxable profit or loss.

Deferred income tax assets related to unused tax losses, tax credits, and deductible temporary differences are recognized only to the extent that it is probable that sufficient future taxable profit will be available against which the deferred tax assets can be utilized. At each reporting date, the Company reassesses the recoverability of deferred income tax assets and recognizes previously unrecognized deferred tax assets to the extent that it has become probable that future taxable profit will allow the deferred tax assets to be recovered.

Revenue Recognition

Revenue is recognized in accordance with IFRS 15, "Revenue from Contracts with Customers", when control of the promised goods or services is transferred to the customer, in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. Determining the timing of the transfer of control, whether at a point in time or over time, requires judgment and can affect the timing of revenue recognition. The Company also applies judgment in determining the transaction price and allocating it to the performance obligations in a contract.

The Company's revenue is derived exclusively from contracts with customers and primarily relates to the sale of crude oil. Revenue is recognized when the Company satisfies a performance obligation by transferring control of the product to the customer, which generally occurs at a point in time when title passes and the customer obtains physical possession of the product. The Company does not have significant performance obligations that are satisfied over time.

Revenue from the sale of crude oil is recognized based on actual volumes delivered at the contracted delivery points and prices. Sales prices are determined with reference to quoted market prices in active markets and are adjusted for quality, transportation, and other contractual terms as applicable. Revenue is recognized on a gross basis, prior to the deduction of transportation costs, and is measured at the fair value of the consideration received or receivable.

Foreign Currency Translation

Transactions denominated in foreign currencies are translated into the functional currency at the exchange rates in effect on the dates of the transactions. Foreign exchange gains and losses arising from the settlement of such transactions, and from the translation of monetary assets and liabilities denominated in foreign currencies at period-end exchange rates, are recognized in the Consolidated Statements of Earnings and Comprehensive Income. Each subsidiary within the consolidated group determines its functional currency as the currency of the primary economic environment in which it operates.

Earnings per Share

The Company presents basic and diluted earnings per share ("EPS") data for its common shares. Basic EPS is calculated by dividing the net profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted EPS is calculated by dividing net profit or loss attributable to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for the effects of all dilutive potential common shares. Dilutive potential common shares consist of share granted under the Company's share-based compensation plans.

Fair Value Measurements

Financial instruments recorded at fair value in the consolidated balance sheet (or for which fair value is disclosed in the notes to the Financial Statements) are categorized based on the fair value hierarchy of inputs. The three levels in the hierarchy are described below:

- Level I - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide continuous pricing information.
- Level II - Pricing inputs are other than quoted prices in active markets included in Level I. Prices in Level II are either directly or indirectly observable as of the reporting date. Level II valuations are based on inputs, including quoted forward for commodities, time value, credit risk and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level III - Valuations are made using inputs for the asset or liability that are not based on observable market data. The Company uses Level III inputs for fair value measurements in inputs such as commodity prices in impairment assessments.

Business Combinations

The Company accounts for acquisitions of corporations or groups of assets as business combinations using the acquisition method when the acquired assets and activities meet the definition of a business under IFRS 3, "Business Combinations". Under the acquisition method, the identifiable assets acquired and liabilities assumed are measured at their fair values at the acquisition date. Any excess of the consideration transferred over the fair value of the net identifiable assets acquired is recognized as goodwill, while any excess of the fair value of the net identifiable assets acquired over the consideration transferred is recognized as a gain on business combination in net earnings. Acquisition-related costs are expensed as incurred. In assessing whether an acquisition constitutes a business, the Company may elect to apply the concentration test on a transaction-by-transaction basis. The concentration test is met when substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets. When the concentration test is met, the acquisition is accounted for as an asset acquisition rather than a business combination. The amendments to IFRS 3 clarify that an acquired set of activities and assets must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create outputs, and narrow the definition of outputs.

Share-Based Compensation

The Company accounts for share-based compensation in accordance with IFRS 2, "Share-based Payment". The Company's share-based compensation arrangements include both equity-settled and cash-settled awards.

Equity-settled awards

Equity-settled awards consist of performance share units ("PSUs") granted to certain employees. PSUs may include dividend equivalent units ("DEUs") that are settled in common shares. The grant-date fair value of PSUs is determined based on the volume-weighted average price of the Company's common shares for the month leading up to the grant date. Performance conditions associated with PSUs are non-market conditions and are reflected in the number of awards expected to vest, rather than in the measurement of grant-date fair value.

Share-based compensation expense for PSUs, including DEUs, is recognized over the vesting period, with a corresponding increase in contributed surplus. While the grant-date fair value of equity-settled awards is not subsequently remeasured, the number of awards expected to vest is adjusted during the year based on the achievement of key performance indicators ("KPIs") approved by the Board of Directors, resulting in a true-up of share-based compensation expense to reflect final performance outcomes. These KPIs are non-market conditions and, once established for the performance period, are not subject to subsequent market-based volatility. Upon issuance of common shares, amounts recognized in contributed surplus related to vested PSUs and DEUs are reclassified to share capital, together with any consideration received.

The Company reviews forfeitures arising from service conditions and, based on historical experience, does not believe forfeitures are material.

Cash-settled awards

Cash-settled awards consist of deferred share units ("DSUs") granted to non-employee directors. DSUs may include DEUs that are settled in cash at the prevailing market price of the Company's common shares and are fully vested upon grant. Cash-settled awards are measured at fair value, with the liability remeasured at each reporting date until settlement. Changes in fair value are recognized in profit or loss for the period.

3. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

NEW ACCOUNTING STANDARD ISSUED BUT NOT EFFECTIVE

A new accounting standard and interpretation was issued and is mandatory for future accounting periods. With respect to IFRS 18, "Presentation and Disclosure in Financial Statements", issued by the IASB in April 2024, the Company is currently evaluating the impact on the Company's Financial Statements. Retrospective application of the standard is mandatory for annual reporting periods starting from January 1, 2027 onwards with earlier application permitted.

4. CASH AND RESTRICTED CASH

	December 31, 2025	December 31, 2024
Cash	$ 112,400	$ 102,783
Restricted cash current	17,039	5,745
Restricted cash non-current	9,685	6,000
Total cash and restricted cash	$ 139,124	$ 114,528

Current restricted cash of $17.0 million is primarily related to funds designated for the erosion control project, the social fund and letters of credit bank guarantees for Block 107 exploration wells. The $9.7 million of non-current restricted cash is related to permitted hedging programs (see Note 8, *Commodity Price Derivatives*) and funds designated for the erosion control project.

In March 2023, Peru's President signed the Supreme Decree authorizing Perupetro S.A. to execute an amendment to Block 95 license contract incorporating a 2.5% social trust fund, calculated based on the value of monthly oil production from the Bretana field, net of transportation costs, for the benefit of local communities. For the years ended December 31, 2025 and 2024, the Company paid to the community $11.3 million and $17.8 million, respectively.

5. TRADE AND OTHER RECEIVABLES

	December 31, 2025	December 31, 2024
Trade receivables	$ 61,586	$ 84,754
VAT receivables	17,980	25,352
Other receivables	1,603	357
Total trade and other receivables	$ 81,169	$ 110,463
Represented as:		
Current receivables	$ 56,862	$ 88,855
Non-current receivables	24,307	21,608
Total trade and other receivables	$ 81,169	$ 110,463

Trade receivables represent revenue from the sale of oil. As of December 31, 2025, trade receivables consisted primarily of $33.8 million related to export sales through Brazil and $27.8 million due from Petroperu, of which $40.8 million is expected to be collected within twelve months and is classified as current, with the remaining $20.8 million classified as non-current. No credit losses have been recognized on the Company's trade receivables as of December 31, 2025 or December 31, 2024.

VAT in Peru is levied on the purchase of goods and services and is recoverable on the sales of goods and services. During the year ended December 31, 2025, the Company paid $30.0 million of VAT and recovered $37.4 million. The Company expects to recover an additional $15.0 million of VAT within the next twelve months. During the year ended December 31, 2024, the Company incurred $39.1 million of VAT and recovered $25.9 million.

VAT receivables have been reclassified in the table above to conform to current period's presentation.

6. INVENTORY

		December 31, 2025		December 31, 2024
Materials, parts and supplies	$	11,092	$	10,894
Oil inventory		1,141		2,676
Total inventory	$	12,233	$	13,570

Materials, parts and supplies, primarily related to drilling, production and maintenance activities, are expected to be consumed in the short term. These inventories are measured at the lower of cost or net realizable value, with provisions recorded for any obsolete or slow-moving items.

Oil inventory consists of barrels of oil production in tanks, measured at the lower of cost or net realizable value. Inventory costs include operating expenses, royalties, transportation and depletion associated with production and are recognized as expense when the inventory is sold. As of December 31, 2025, the Company’s oil inventory balance was $1.1 million, representing 35.6 thousand barrels valued at $32.10 per barrel, compared to $2.7 million, representing 85.9 thousand barrels at $31.16 per barrel, as of December 31, 2024.

7. PREPAID EXPENSES

		December 31, 2025		December 31, 2024
Erosion control project advances	$	7,128	$	3,296
Advances to contractors		7,401		7,450
Prepaid expenses and others		2,854		4,226
Total prepaid expenses	$	17,383	$	14,972
Represented as:				
Current prepaid expenses	$	10,383	$	7,972
Non-current prepaid expenses		7,000		7,000
Total prepaid expenses	$	17,383	$	14,972

As of December 31, 2025, advances for the erosion control project primarily related to a down payment for steel beam materials. Advances to contractors included $7.0 million related to power plant projects classified as long term. Prepaid expenses and others comprised $1.4 million for insurance, prepaid consulting services and other related services and $1.5 million in Peruvian income tax prepayments.

Certain prior period balances previously included in prepaid expenses and other have been reclassified to income tax payables to more accurately reflect the nature and composition of the liability.

8. RISK MANAGEMENT

	December 31, 2025		December 31, 2024	
	Carrying	Fair Value	Carrying	Fair Value
Cash and restricted cash	$ 139,124	$ 139,124	$ 114,528	$ 114,528
Trade and other receivables	41,878	41,878	65,832	65,832
Short-term derivative assets	967	967	1,307	1,307
Trade receivable long-term	21,311	21,311	19,279	19,279
Long-term derivative assets	—	—	311	311
Short and long-term debt	43,040	43,040	10,047	10,047
Trade and other payables	58,384	58,384	94,955	94,955
Long-term derivative liabilities	$ 21,710	$ 21,710	$ 10,534	$ 10,534

The table above presents the Company's carrying amount and fair values of financial instruments including cash and restricted cash, trade and other receivables, derivatives, debt, and trade and other payables. These instruments are classified as financial assets and liabilities and are measured at either amortized cost or fair value. The Company is exposed to various financial risks arising from its normal-course business activities.

COMMODITY PRICE DERIVATIVES

The derivative assets and liabilities are classified as a Level 2 fair value measurement. The Petroperu Saramuro agreement, signed in 2021, includes a purchase price adjustment clause. The initial sales price is based on the arithmetic average of Intercontinental Exchange ("ICE") Brent Crude 8-month forward price, while the realized price is based on the tender price of the oil sold at the Bayovar terminal. The purchase price adjustment is calculated as the realized price less the initial sales price. If the purchase price adjustment is negative, the Company compensates Petroperu for the amount, multiplied by the volume sold or arranged by Petroperu. Conversely, if the purchase price adjustment is positive, the Company is compensated by Petroperu.

The fair value of the embedded derivative, reflecting the average future Brent price differential, was recorded as a gain (loss) on commodity price derivatives as of December 31, 2025 and 2024.

	December 31, 2025	December 31, 2024
Net derivative (liability) asset at beginning of period	$ (8,916)	$ 7,412
Cash settlements	(1,822)	(5,904)
Realized gain (loss)	1,822	(3,741)
Unrealized loss	(11,827)	(6,683)
Net derivative liability at end of period	$ (20,743)	$ (8,916)

	December 31, 2025	December 31, 2024
Short-term derivative assets	$ 967	$ 1,307
Long-term derivative assets	—	311
Long-term derivative liabilities	(21,710)	(10,534)
Net derivative liability at end of period	$ (20,743)	$ (8,916)

Sales delivery / Executed month	Expected settlement month	Volume (bbls. in thousands)	Price range $/bbl.[3]	Hedged range $/bbl.	Net derivative asset (liability)
Peru Embedded Derivatives [(1)]					
Apr-21 to Feb-22	Oct-27 to Apr-28	1,882	$62.49 to $85.26	$61.93 to $62.79	$ (21,710)
Corporate Derivatives Hedging [(2)]					
Jan-25	Jan-26	227	—	$65.00 to $100.50	967
				Net derivative liability	**$ (20,743)**

(1) Embedded derivative related to original Petroperu sales agreement.

As of December 31, 2025 and December 31, 2024, approximately 1.9 million barrels remain in the pipeline or storage tanks, awaiting final sale by Petroperu. During the year, a decrease in future oil prices related to the Peru embedded derivative resulted in an increase to the net derivative liability. A 1.0% change in the Peru embedded derivative hedged range price would result in an estimated $1.2 million change to the net derivative liability. Derivative gains and losses are only realized when oil is effectively sold to third parties at Bayovar.

(2) Corporate hedge program covers a portion of 2025 and 2026 production.

During the year, the Company entered into Brent oil hedging contracts totaling 1.6 million barrels. The hedges consisted of two three-way collar contracts: one with a put price of $65 per barrel, a call price of $79 per barrel, and a call ceiling of $99 per barrel, and another with a put price of $65 per barrel, a call price of $80.5 per barrel, and a call ceiling of $100.5 per barrel.

As of December 31, 2025, approximately 0.2 million hedged barrels of Brent oil remained under the corporate hedge program, resulting in a net derivative asset of $1.0 million. No new corporate hedges were executed during the quarter.

(3) Represents the price per barrel at which the oil was originally sold.

FOREIGN EXCHANGE RATE RISK

The Company's functional currency is the United States dollar. Foreign exchange gains or losses may arise from the translation of working capital items denominated in currencies other than the functional currency of the jurisdiction in which the working capital item is held.

LIQUIDITY RISK

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with its financial liabilities. The Company's liquidity risk is affected by current and future commodity prices. If required, the Company may consider additional short-term financing or issuing equity to meet its future obligations. Declines in future commodity prices could affect the Company's ability to fund ongoing operations. The current economic environment may have significant adverse impacts on the Company including, but not exclusively:

- material declines in revenue and cash flows due to lower commodity prices;
- declines in revenue and operating activities resulting from constrained capital programs and oil production;
- inability to access financing sources; and,
- increased risk of non-performance by the Company's customers and suppliers.

Estimates and judgments made by management in the preparation of the Financial Statements are subject to a certain degree of measurement uncertainty during this volatile period.

CREDIT RISK

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due, resulting in a financial loss to the Company. The Company's VAT receivable is primarily for sales tax credits on exploration and drilling expenses incurred in the current year and prior years. These credits are applied to future oil development activities or recovered in accordance with the current sales tax recovery legislation.

The Company's trade receivable balance primarily relates to oil sales and purchase price adjustments with two customers: Petroperu, a state-owned company, and Novum Energy Trading Corp, an oil trading company. The Company has a long-term sales agreement for oil exports through Brazil, with sales on a free on board ("FOB") Bretana basis. Sales to the Iquitos refinery or into the port of Pucallpa are due 60 days after final delivery. Sales through the Oleoducto Norperuano Pipeline ("ONP") are due 240 days after final delivery to the Bayovar terminal.

During the year ended December 31, 2025, PetroTal sold substantially all of its oil through two primary routes: 92.4% via the Brazil export route, and 7.4% to the local Iquitos refinery. Sales via the ONP remained inactive during the period, and sales to the local Iquitos refinery resumed as of September 2025. The Company has not experienced any material credit losses on trade receivables and periodically assesses the recoverability through customer discussions, credit rating agency reports and other third-party information.

Impairment of a financial asset is recognized only when there is objective evidence of impairment, the loss event impacts on future cash flow and can be reliably estimated. Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. Management believes there is no significant risk on the recoverability of the Company's receivables; accordingly, no impairment has been recorded.

The Company deposits cash and restricted cash with a limited number of high-quality financial institutions. The maximum credit exposure associated with financial assets is their carrying value. As of December 31, 2025, the

Company's cash and restricted cash are predominantly denominated in U.S. dollars, with financial institutions located across the U.S., Canada and Peru.

9. EXPLORATION AND EVALUATION ASSETS

		Exploration and Evaluation Assets
Balance at January 1, 2024	$	8,973
Additions		1,433
Balance at December 31, 2024	$	10,406
Additions		1,004
Balance at December 31, 2025	$	11,410

E&E assets represent the Company's exploration projects that are pending the determination of proved or probable reserves or the assessment of recoverability. As of December 31, 2025 and December 31, 2024, the Company determined there were no impairment indicators of the E&E balance.

10. PROPERTY, PLANT AND EQUIPMENT

		Petroleum Properties		Right of Use Assets		Other Assets		Total
Balance at January 1, 2024	$	364,226	$	32,868	$	2,470	$	399,564
Additions		157,620		28,125		3,773		189,518
Revisions to decommissioning obligations		181		—		—		181
Asset acquisition		9,078		—		—		9,078
Revisions to right of use asset		—		1,045		—		1,045
Depletion, depreciation and amortization		(59,124)		(2,470)		(774)		(62,368)
Balance at December 31, 2024	$	471,981	$	59,568	$	5,469	$	537,018
Additions		74,231		6,563		403		81,197
Revisions to decommissioning obligations		6,232		—		—		6,232
Revisions to right of use asset		—		25		—		25
Depletion, depreciation and amortization		(77,104)		(5,039)		(548)		(82,691)
Balance at December 31, 2025	$	475,340	$	61,117	$	5,324	$	541,781

Depreciation, depletion and amortization expenses included in inventory was $0.3 million as of December 31, 2025 and $0.4 million as of December 31, 2024. As of December 31, 2025, there were no indicators of impairment.

Certain reclassifications were made to prior year balances in the table above to more accurately reflect the nature and composition of the asset categories.

ASSET ACQUISITION

On November 29, 2024, the Company completed the acquisition of Ucawa Energy S.A.C. (formerly CEPSA Peruana S.A.C.), which holds a 100% working interest in Peru's Block 131, for total cash consideration of $6.7 million, resulting in the recognition of approximately $22.2 million of assets acquired and $15.5 million of liabilities assumed. The Company applied the optional concentration test permitted under IFRS 3 "Business Combinations" and concluded that substantially all of the fair value of the gross assets acquired was concentrated in a single identifiable asset or group of similar assets; accordingly, the transaction was accounted for as an asset acquisition rather than a business combination. As a result, the purchase price, including directly attributable transaction costs of $0.3 million, was capitalized and allocated to the identifiable assets and liabilities acquired on a relative fair value basis at the acquisition date. The amounts recognized at the acquisition date for the identifiable net assets acquired were as follows:

	November 29, 2024
Net assets acquired	
Cash	4,988
Trade receivables and other assets	5,179
Property, plant and equipment, net	12,036
Trade and other payables	(1,926)
Decommissioning liabilities	(13,590)
Total net asset acquired	**6,687**
Purchase consideration	6,687
Total purchase consideration	**6,687**

11. DEBT

	December 31, 2025	December 31, 2024
Short-term debt	$ 11,408	$ 10,047
Long-term debt	31,632	—
Total debt	$ 43,040	$ 10,047

On May 9, 2025, the Company entered into a syndicated loan agreement with Corporación Financiera de Desarrollo S.A. ("COFIDE"), a state-owned development bank in Peru, and Banco Interamericano de Finanzas ("BanBif") for a total of $65.0 million. The four-year amortizing term loan matures in April 2029 and carries a fixed interest rate of 8.65%. As of December 31, 2025, the Company had $43.0 million outstanding under the loan related to the erosion control project, of which $11.4 million was classified as short-term and $31.6 million as long-term. The outstanding principal balance approximates fair market value. The loan agreement includes financial covenants requiring the Company to maintain: (i) a 1.2x current assets to current liabilities minimum liquidity ratio, (ii) a 2.0x liabilities to equity maximum debt ratio, and (iii) a 1.2x minimum debt service coverage ratio. As of the reporting date, the Company was in full compliance with all applicable covenant requirements.

Transaction costs of $0.9 million incurred in connection with the loan were netted against the loan liability upon initial recognition and are being amortized over the term of the loan using the effective interest method.

The Company has $34.0 million of available credit under its credit facilities, each with a one-year term and renewal options. The loan agreements contain no debt covenants. The credit facilities are intended to fund short-term working capital needs, subject to bank approval at the time of each draw. Borrowings under the facilities bear interest at each bank's effective annual rate. The applicable rate is determined at the time of draw based on the Company's credit profile and prevailing market conditions, in accordance with local banking regulations. As of December 31, 2025, the effective annual rates offered by the banks ranged from 4.30% to 6.00%.

The following is a summary of scheduled debt maturities by year as of December 31, 2025:

Year		
2026	$	11,408
2027		12,352
2028		13,441
2029		5,839
Total		43,040

12. TRADE AND OTHER PAYABLES

		December 31, 2025		December 31, 2024
Trade payables	$	19,501	$	39,201
Accrued payables and other obligations		38,883		55,754
Total trade and other payables	$	58,384	$	94,955

As of December 31, 2025 and December 31, 2024, trade payables and other payables were primarily related to the drilling and completion of wells and construction of production processing facilities. The decrease in trade payables and accruals during the year reflected lower drilling activity. Other obligations were mainly related to the 2.5% social fund for the benefit of local communities, which totaled $0.2 million and $5.0 million as of December 31, 2025 and December 31, 2024, respectively. The decrease in the social fund balance as of December 31, 2025 primarily reflects payments made during the year against amounts accrued in the prior year. See Note 16, *Revenue Net of Royalties and Social Fund*, for further details.

13. DECOMMISSIONING LIABILITIES

The undiscounted, uninflated value of estimated decommissioning liabilities was $71.4 million and $64.4 million as of December 31, 2025 and December 31, 2024, respectively. The present value of the liabilities was calculated using average risk-free rates between 5.3% to 5.7% as of December 31, 2025 and 4.8% to 6.3% as of December 31, 2024, to reflect the market assessment of the time value of money as well as risks specific to the liabilities that have not been included in the cash flow estimates. The inflation rate used in determining the cash flow estimate was 2.0%. The revisions to the decommissioning liabilities include changes to cost estimates, the risk-free rates and adjustments for inflation. The obligations are primarily expected to be settled at the end of the exploration licenses between 2037-2041, of which $0.5 million is expected to be settled in 2027.

In 2024, the Company recognized $13.6 million of decommissioning liabilities in connection with the acquisition of assets from Ucawa Energy S.A.C. See Note 10, *Asset Acquisition*, for additional information.

		Decommissioning Liabilities
Balance at January 1, 2024	$	22,147
Additions		3,205
Asset acquisition		13,590
Revisions to decommissioning liabilities		(5,851)
Accretion of decommissioning liabilities		1,292
Balance at December 31, 2024	$	34,383
Revisions to decommissioning liabilities		6,232
Accretion of decommissioning liabilities		2,153
Balance at December 31, 2025	$	42,768

The following table demonstrates the change in decommissioning liabilities as a result of reasonably possible changes in discount rate.

		December 31, 2025		December 31, 2024
Increase of 1%	$	(5,554)	$	(4,716)
Decrease of 1%		6,469		5,417

The following table demonstrates the change in decommissioning liabilities as a result of reasonably possible changes in cost.

		December 31, 2025		December 31, 2024
Increase of 1%	$	428	$	343
Decrease of 1%		(428)		(343)

14. LEASE LIABILITIES

The Company has lease liabilities related to drilling equipment, power generation equipment, and office premises in Houston, Texas and Lima, Peru, with lease terms ranging from 3 to 8 years.

Lease liabilities are measured at the present value of future lease payments, discounted using the applicable incremental borrowing rate at lease commencement, which ranges from 8.5% to 9.5%.

During the first quarter of 2025, the Company entered into a new power plant equipment lease with a purchase option, resulting in a $4.2 million increase in the present value of right-of-use assets and lease liabilities on the balance sheet. During the fourth quarter, an additional $2.3 million increase in lease liabilities was recorded related to commissioning activities of the drilling rig lease. The lease liability was measured using an incremental borrowing rate of 8.65%, and the lease term extends to February 2030.

In the fourth quarter of 2024, the Company executed an addendum to the power generation equipment lease to obtain additional equipment, resulting in a $15.0 million increase in present value of right-of-use assets and lease liabilities. The Company has an option to purchase the equipment on June 27, 2031 for $3.0 million. The lease liabilities was measured using an incremental borrowing rate of 8.5%, and the lease term extends to September 2031.

Also the fourth quarter of 2024, the Company entered into an agreement to acquire a drilling rig from a Houston-based equipment provider. The acquisition was financed through a 36-month lease arrangement with a Peruvian bank, resulting in a $13.3 million increase in the present value of right-of-use assets and lease liabilities. The lease liability was measured using an incremental borrowing rate of 8.5%, and the lease term extends to December 2027. The Company has an option to purchase the rig on October 31, 2028 for $0.1 million. Based on current operating plans and the impairment assessment performed during the year, management determined that exercise of the purchase option is not reasonably certain. Accordingly, the option has not been included in the lease term or measurement of the lease liability.

Lease liabilities at January 1, 2024	$	28,870
Additions		28,125
Acquisition		15
Revisions		1,045
Payments		(5,819)
Interest on leases		2,405
Lease liabilities at December 31, 2024	$	54,641
Additions		6,563
Revisions		25
Payments		(10,061)
Interest on leases		4,556
Lease liabilities at December 31, 2025	$	55,724
Represented as:		
Current liability	$	12,457
Non-current liability		43,267
Total lease liabilities	$	55,724

The following is a summary of minimum undiscounted annual lease payments by year as of December 31, 2025:

Year		
2026	$	15,062
2027		14,591
2028		14,034
2029		8,019
2030		6,961
Thereafter		7,451
Total	$	66,118

15. SHARE CAPITAL

Authorized share capital consists of an unlimited number of common shares without nominal or par value. Holders of common shares are entitled to one vote per share and to receive dividends as declared by the Board of Directors.

	Thousands of Common Shares		Share Capital
Balance at January 1, 2024	912,314	$	140,672
Vesting of performance share units	8,283		—

Repurchase of shares	(8,814)	(1,474)
Balance at December 31, 2024	911,783 $	139,198
Vesting of performance share units	6,094	—
Repurchase of shares	(4,901)	(970)
Balance at December 31, 2025	912,976 $	138,228

DIVIDENDS

During the years ended December 31, 2025 and 2024, the Company paid dividends to shareholders of $41.3 million and $60.5 million, respectively. The Company paid dividends per share in the amount of $0.015 during the first through third quarter of 2025.

NORMAL COURSE ISSUER BID ("NCIB")

On June 3, 2025, the Company renewed the NCIB, which will end no later than June 2, 2026. The renewal allows the purchase of up to 45.8 million common shares, representing approximately 5.0% of its outstanding common shares as of December 31, 2025. Purchases are subject to a daily limit of 0.2 million shares, with one block purchase per calendar week allowed to exceed this limit. Common shares purchased under the NCIB are either cancelled or used to settle employee share-based awards.

During the years ended December 31, 2025 and 2024, the Company purchased 4.9 million and 8.8 million common shares under the NCIB for total consideration of $2.5 million and $4.9 million, respectively. The surplus between the total consideration and the carrying value of the shares repurchased was recorded against retained earnings.

SHARE BASED COMPENSATION

The Company has granted PSUs to certain employees and DSUs to non-employee directors under the Company's share-based compensation plans.

PSUs vest either after three years or in equal annual installments over three years. PSUs may include DEUs that are settled in common shares. The number of PSUs, including DEUs, that ultimately vest is determined based on the achievement of specified performance conditions. These conditions consist of KPIs approved annually by the Board of Directors and are based on internal operational, financial, and strategic performance objectives. These KPI factors are non-market conditions and, once established for the performance period, are not subject to subsequent market-based volatility. Share-based compensation expense is adjusted during the year to reflect the final number of awards expected to vest based on Board-approved performance outcomes, and the final number of shares follows the applicable vesting schedule.

DSUs are granted to non-employee directors under the Company's DSU plan. DSUs are fully vested upon grant and are redeemable upon a holder ceasing to be a director of the Company. DSUs may include DEUs that are settled in cash at the prevailing market price of the Company's common shares.

The following tables detail the PSU and DSU activity and outstanding balances as of December 31, 2025 and 2024:

	Performance Share Units	Deferred Share Units
Balance at January 1, 2024	20,801,920	3,792,494
Additions	8,930,275	2,044,369
Issued	(9,910,871)	—
Forfeited	(1,542,321)	—
Exercised/settled	—	(765,428)

Balance at December 31, 2024	18,279,003	5,071,435
Additions	13,583,304	2,322,526
Issued	(12,519,467)	—
Forfeited	(3,434,940)	—
Balance at December 31, 2025	15,907,900	7,393,961

The Company recognized $3.7 million and $3.2 million of share-based compensation expense during the years ended December 31, 2025 and 2024, respectively, which is included in general and administrative expenses in the Consolidated Statements of Earnings and Other Comprehensive Income.

16. REVENUE NET OF ROYALTIES AND SOCIAL FUND

The Company's oil revenue is recognized in accordance with the terms of its sales agreements. The transaction price is based on market index commodity prices for the month of production, adjusted for quality, allowable deductions and other factors.

	Year Ended December 31,	
	2025	**2024**
Oil revenue	$ 316,891	$ 373,940
Royalty	(29,117)	(29,518)
Social fund	(9,120)	(10,429)
Total oil revenue net of royalties and social fund	$ 278,654	$ 333,993

The Company sold 7.0 million and 6.4 million barrels of oil during the years ended December 31, 2025 and 2024, respectively, at a net realized sales price of $45.19 per barrel and $58.19 per barrel, respectively, net of price discounts.

17. RELATED PARTY TRANSACTIONS

The Company did not enter into any related party transactions or off-balance sheet arrangements during the years ended December 31, 2025 and 2024. Key management personnel compensation, including directors, is as follows:

	Year Ended December 31,	
	2025	**2024**
Salaries, incentives and short term benefits	$ 2,518	$ 2,021
Directors' fees	1,629	1,322
Share-based compensation	1,598	1,736
Total	$ 5,745	$ 5,079

18. TAXES

The Company's effective tax rate is impacted by the relative pre-tax income earned by the Company's operations in Canada, U.S. and Peru. The Company is subject to statutory tax rates of 23.0% in Canada, 21.0% in the U.S. and 32.0% in Peru (activities of the Company in Peru are subject to a 30.0% statutory tax rate plus 2.0% in accordance with Law 27343). The Company files federal income tax returns and local income tax returns in the various jurisdictions.

The tax at the effective rate differed from the tax at the statutory rate as follows:

	Year Ended December 31,	
	2025	2024
Earnings before income taxes	$ 62,577	$ 151,352
Canadian corporate tax rate	23%	23%
Expected income tax expense	$ 14,393	$ 34,811
Increase (decrease) in taxes resulting from:		
Non-deductible expenses and other	1,120	(1,349)
Tax differential on foreign jurisdictions	624	6,440
Change in valuation allowance and NOL reduction	2,253	—
Provision for income taxes	$ 18,390	$ 39,902

The Company recognized the deferred tax assets and deferred tax liabilities in Canada, Peru, and the U.S arising from temporary differences. As of December 31, 2025, the Company consumed all net operating losses ("NOLs") of $2M in the U.S., and as of December 31, 2024, the Company consumed all non-capital losses of $26M in Canada.

Ucawa has $96.1 million in tax losses as of December 31, 2025, compared to $82.0 million as of December 31, 2024 and no deferred tax asset has been recognized. These losses are being carried forward and are available to offset against future tax gains.

As of December 31, 2025, the aggregate amount of temporary differences related to investments in subsidiaries for which deferred tax liabilities have not been recognized was approximately $56.4 million, compared to $22.0 million as of December 31, 2024.

Certain prior period balances previously included in prepaid expenses and other have been reclassified to income tax payables to more accurately reflect the nature and composition of the liability.

19. COMMITMENTS AND CONTINGENCIES

As of December 31, 2025, the Company holds the following letters of credit guaranteeing its commitments in exploration Block 107:

Block	Beneficiary	Amount	Commitment	Expiration
107	Perupetro S.A.	$ 1,500	1st exploration well, minimum work 5th exploratory period	Mar-27
107	Perupetro S.A.	1,500	2nd exploration well, minimum work 5th exploratory period	Mar-27
		$ 3,000		

In December 2024, PetroTal signed two Technical Evaluation Agreements with Perupetro for Blocks 97 and 98, which are located in the vicinity and on trend with PetroTal's Block 131, as well as the Aguaytia and Agua Caliente fields in Peru's Ucayali Basin. The agreements include contractual commitments to be executed in two 12-month phases and primarily include geological and geophysical studies such as seismic imaging, geochemical modeling and hydrocarbon potential evaluation reports.

The Company continued its preventive riverbank erosion control program to protect the Bretana field and the surrounding community. The Company has committed to a $65.0 - $75.0 million erosion control project, which will be allocated to operating expense and/or capital expenditures depending on the nature of outflow and who received the benefits (i.e. the Company or the community).

As part of Ucawa Energy S.A.C. asset acquisition, a tax administrative and a judicial legal case were assessed as possible, representing a total legal contingency of approximately $2.8 million. Pursuant to clause 12.5 of the Purchase Agreement, the seller, CEPSA S.A., is obligated to indemnify PetroTal against any related legal action and/or fines, if applicable.

20. SUBSEQUENT EVENT

On January 20, 2026, PetroTal notified a Peruvian bank of its intention to terminate its lease agreement relating to the Amazonia-1 drilling rig. The Company is evaluating options to dispose of the drilling rig.