



Q1 2026 REPORTING PACKAGE

May 6, 2026

PetroTal Announces Q1 2026 Financial and Operating Results

Calgary, AB and Houston, TX – May 7, 2026 – PetroTal Corp. (“PetroTal” or the “Company”) (TSX: TAL, AIM: PTAL and OTCQX: PTALF) is pleased to report its operating and financial results for the three months ended March 31, 2026. All amounts herein are in United States dollars unless stated otherwise.

Selected financial and operational information outlined above should be read in conjunction with the Company’s unaudited consolidated financial statements and management’s discussion and analysis (“MD&A”) for the three months ended March 31, 2026, which are available on SEDAR+ at www.sedarplus.ca and on the Company’s website at www.PetroTal-Corp.com.

Key Highlights

- Average Q1 2026 sales and production of 14,350 and 14,907 barrels of oil per day (“bopd”), respectively;
- Adjusted EBITDA⁽¹⁾ of \$35.1 million (\$27.22/bbl) represents a 90% increase relative to the prior quarter;
- Free Funds Flow⁽¹⁾ of \$25.7 million in Q1 2026, compared to \$3.3 million in Q4 2025;
- Total cash of \$128.3 million as of March 31, 2026, compared to \$113.6 million in March 2025;
- 2026 Adjusted EBITDA guidance range increases to \$110-120 million, from \$30-40 million previously;
- Executed contract with third-party drilling service provider, ahead of planned resumption of development drilling in October 2026.

(1) Non-GAAP (defined below) measure that does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures presented by other entities. See “Selected Financial Measures” section.

Manuel Pablo Zuniga-Pflucker, President and Chief Executive Officer, commented:

“Our first quarter results reflect a continued focus on maintaining production at Bretana and positioning the Company for a return to growth, while also highlighting the positive impact of improving crude oil prices. Stronger realized pricing in March contributed to a 90% increase in Adjusted EBITDA compared to the prior quarter, despite lower production volumes in the period. This result demonstrates the Company’s operating leverage and ability to generate meaningful cash flow even at lower production levels.”

At Bretana, we remain focused on preparing the field for its next phase of growth. During the quarter and into April, we advanced key infrastructure initiatives, including stimulation work on water injection wells to increase injection capacity and help stabilize production ahead of our upcoming drilling campaign. We are already seeing the benefit of this work, with year-to-date sales volumes tracking slightly ahead of expectations as we approach the midpoint of the second quarter.

In parallel, we have made good progress towards resuming our development drilling program. We recently signed a contract with a third-party drilling company and are advancing plans to mobilize the rig to the field, with drilling expected to begin in October 2026. We also plan to carry out pulling jobs in three wells in the third quarter, which we have scheduled ahead of the resumption of our drilling campaign, to help optimize performance and reduce the potential for production disruptions later in the year.

Looking ahead, our priorities remain clear: sustain and build production at Bretana, execute our capital program, and position the Company to return to growth. We believe the steps we are taking today will improve operational reliability, support efficient capital deployment, and create long-term value for our shareholders.”

Selected Financial Highlights

	Three Months Ended					
	Q1-2026		Q4-2025		Q1-2025	
	\$/bbl	\$(000's)	\$/bbl	\$(000's)	\$/bbl	\$(000's)
Average Production (bopd)		14,907		15,258		23,281
Average Sales (bopd)		14,350		15,059		23,286
Total Sales (bbls)		1,291,473		1,385,460		2,095,714
Average Brent Price	\$74.65		\$62.46		\$73.96	
Contracted Sales Price, Gross	\$74.50		\$62.49		\$73.89	
Tariffs, Fees and Differentials	-\$23.43		-\$22.82		-\$21.43	
Realized Sales Price, Net	\$51.07		\$39.67		\$52.46	
Oil Revenue	\$51.07	\$65,950	\$39.67	\$54,959	\$52.46	\$109,951
Royalties	\$4.92	\$6,351	\$6.32	\$8,759	\$5.84	\$12,241
Operating Expenses	\$8.46	\$10,928	\$14.35	\$19,883	\$6.31	\$13,227
Direct Transportation						
Diluent	\$0.00	\$0	\$0.00	\$0	\$0.00	\$0
Barging	\$0.48	\$626	\$0.48	\$670	\$0.79	\$1,664
Diesel	\$0.00	\$0	\$0.00	\$0	\$0.00	\$0
Storage	\$0.00	\$0	\$0.22	\$301	\$0.30	\$636
Total Transportation	\$0.48	\$626	\$0.70	\$971	\$1.09	\$2,300
Net Operating Income	\$37.21	\$48,045	\$18.30	\$25,346	\$39.22	\$82,183
Erosion Control	\$3.15	\$4,070	\$2.95	\$4,083	\$0.87	\$1,816
G&A	\$6.75	\$8,712	\$3.52	\$4,877	\$4.57	\$9,579
EBITDA	\$27.34	\$35,313	\$11.83	\$16,386	\$33.78	\$70,788
Adjusted EBITDA	\$27.22	\$35,148	\$13.38	\$18,543	\$34.29	\$71,860
Net Income	\$11.84	\$15,297	-\$5.61	-\$7,777	\$14.72	\$30,852
Basic Shares Outstanding ('000)		920,328		915,930		915,930
Market Capitalization		\$362,885		\$256,460		\$435,754
Net Income/Share (\$/sh)		\$0.01		-\$0.01		\$0.03
Capex		\$7,622		\$15,286		\$23,624
Free Funds Flow		\$25,728		\$3,257		\$48,236
Total Cash		\$128,327		\$139,124		\$113,565
Available Cash		\$104,347		\$112,400		\$102,650E

1. Approximately 98% of Q1 2026 sales were through the Brazilian route vs 88% in Q4 2025.
2. Royalties include the impact of the 2.5% community social trust.
3. Non-GAAP (defined below) measure that does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures presented by other entities. See "Selected Financial Measures" section.
4. Net operating income represents revenues less royalties, operating expenses, and direct transportation.
5. Adjusted EBITDA is net operating income less general and administrative ("G&A") and plus/minus realized derivative impacts.
6. Market capitalization for Q1 2026, Q4 2024 and Q1 2025 assume share prices of \$0.3943, \$0.2757 and \$0.4758 respectively on the last trading day of the period.
7. Free funds flow is defined as adjusted EBITDA less capital expenditures. See "Selected Financial Measures" section.
8. Includes restricted cash balances.

Additional financial and operational updates during and subsequent to the quarter ending March 31, 2026:

Operations Update

PetroTal continues to advance key operational initiatives at the Bretana field, positioning the Company to resume development drilling in October 2026. The Company has executed a contract with a third-party drilling service provider, whose rig is currently completing operations in Colombia. Following demobilization, the rig is expected to be transported to Peru by road and river, similar to prior equipment moves. Infrastructure work to position the drilling rig, along with the electromechanical activities required to tie in new wells to existing facilities, is progressing as planned. The operations team is also preparing to facilitate the rapid connection of the new wells, optimizing early production rates.

In April 2026, PetroTal conducted stimulation work on three of the four water injection wells at the Bretana field. The program was designed to increase formation water disposal capacity from the first quarter 2026 average of approximately 170,000 barrels of water per day (“bwpd”), to help support oil production ahead of the resumption of development drilling later this year. Bretana field production averaged approximately 12,850 bopd in April, reflecting brief, planned shut-ins of producing wells during the stimulation work. Since completing the program, production has increased, averaging approximately 13,050 bopd in the first week of May, while water injection capacity has risen to just over 180,000 bwpd.

In Q3 2026, PetroTal plans to carry out pulling jobs in three producing wells at Bretana, in keeping with expectations outlined in the Company’s 2026 budget guidance. This work is being advanced ahead of the planned restart of development drilling later this year.

Erosion Control Project

PetroTal expensed \$4.1 million for erosion control in Q1 2026, consistent with the prior quarter, bringing total cumulative investment in the project to \$36.8 million as of March 31, 2026. As disclosed previously, PetroTal terminated the erosion control project contract with the prior construction consortium in March 2026 and has initiated a procurement process to secure new contractors to complete the project. The tender process is underway and the Company will provide additional updates as necessary.

Cash and Liquidity Update

PetroTal ended Q1 2026 with a total cash position of \$128.1 million, of which \$104.2 million was unrestricted. This compares to total cash of \$139.1 million at the end of Q4 2025 and \$113.6 million at the end of Q1 2025. The

decrease in cash relative to the prior quarter is primarily due to the settlement of annual cash taxes, which amounted to approximately \$10 million in Q1 2026. PetroTal's trade receivables increased by \$23.4 million relative to the prior quarter, as the Company benefited from stronger realized pricing in the month of March.

PetroTal has not initiated any new production hedges since the end of March 2026. In line with previous disclosure, the Company maintains hedges on approximately 0.9 million barrels over the remainder of 2026. The costless collars have an average Brent floor price of \$60.00/bbl and a ceiling of \$80.50/bbl, with a cap of \$100.50/bbl. As of April 21, PetroTal's production hedges had a fair value of negative \$11 million.

Guidance Update

PetroTal's original 2026 guidance, released on January 20, 2026, was based on an assumed annual Brent oil price of \$60.00/bbl and contemplated Adjusted EBITDA of \$30-40 million for the full year. Supported by an average dated Brent oil price of \$74.65/bbl during the first quarter of 2026, the Company generated approximately that level of Adjusted EBITDA during Q1 alone.

Incorporating first quarter actual results and updating the forecast for recent Brent strip pricing, PetroTal now expects to generate Adjusted EBITDA of approximately \$110-120 million for full-year 2026.

This updated guidance is driven solely by changes in the Company's oil price assumptions. PetroTal is not currently anticipating any material changes to its previously disclosed production outlook, major operating cost assumptions, or 2026 capital expenditure budget.

Corporate Presentation Update

The Company has updated its Corporate Presentation, available for download or viewing at https://petrotalcorp.com/investors/Q1_2026

Webcast Link for May 7, 2026

PetroTal's management team will host a webcast to discuss Q1 2026 results on May 7, 2026 at 9:00am CT (Houston) and 3:00pm BST (London). Please see the link below to register.

https://brrmedia.news/PTAL_Q1_26

ABOUT PETROTAL

PetroTal is a publicly traded, tri-quoted (TSX: TAL, AIM: PTAL and OTCQX: PTALF) oil and gas development and production Company domiciled in Calgary, Alberta, focused on the development of oil assets in Peru. PetroTal's flagship asset is its 100% working interest in the Bretaña Norte oil field in Peru's Block 95, where oil production was initiated in June 2018. In early 2022, PetroTal became the largest crude oil producer in Peru. The Company's management team has significant experience in developing and exploring for oil in Peru and is led by a Board of Directors that is focused on safely and cost effectively developing the Bretaña oil field. It is actively building new initiatives to champion community sensitive energy production, benefiting all stakeholders. For further information, please see the Company's website at www.petrotal-corp.com, the Company's filed documents at www.sedarplus.ca, or below:

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FORWARD-LOOKING STATEMENTS: This press release contains certain statements that may be deemed to be forward-looking statements. Such statements relate to possible future events, including, but not limited to: oil production levels and production

capacity; PetroTal's drilling, completions and other activities; the ability of the Company to access alternate export routes, including the Oleoducto Norperuano, and the consistent reliability of those options; the timing of filing the Annual Information Form. In addition, statements relating to expected production, reserves, recovery, costs and valuation are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "believe", "expect", "plan", "estimate", "potential", "will", "should", "continue", "may", "objective", "intend" and similar expressions. The forward-looking statements provided in this press release are based on management's current belief, based on currently available information, as to the outcome and timing of future events. The forward-looking statements are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning the ability of existing infrastructure to deliver production and the anticipated capital expenditures associated therewith, the ability to obtain and maintain necessary permits and licenses, the ability of government groups to effectively achieve objectives in respect of reducing social conflict and collaborating towards continued investment in the energy sector, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal's products, including pursuant to hedging arrangements, the availability and performance of drilling rigs, facilities, pipelines, other oilfield services and skilled labour, royalty regimes and exchange rates, the impact of inflation on costs, the application of regulatory and licensing requirements, the accuracy of PetroTal's geological interpretation of its drilling and land opportunities, current legislation, receipt of required regulatory approval, the success of future drilling and development activities, the performance of new wells, future river water levels, the Company's growth strategy, general economic conditions and availability of required equipment and services. PetroTal cautions that forward-looking statements relating to PetroTal are subject to all of the risks, uncertainties and other factors, which may cause the actual results, performance, capital expenditures or achievements of the Company to differ materially from anticipated future results, performance, capital expenditures or achievements expressed or implied by such forward-looking statements. Factors that could cause actual results to differ materially from those set forth in the forward-looking statements include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; and health, safety and environmental risks), business performance, legal and legislative developments including changes in tax laws and legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures, credit ratings and risks, fluctuations in interest rates and currency values, changes in the financial landscape both domestically and abroad, including volatility in the stock market and financial system, wars (including Russia's war in Ukraine and the Israeli-Hamas conflict), regulatory developments, commodity price volatility, price differentials and the actual prices received for products, exchange rate fluctuations, legal, political and economic instability in Peru, access to transportation routes and markets for the Company's production, changes in legislation affecting the oil and gas industry, changes in the financial landscape both domestically and abroad (including volatility in the stock market and financial system) and the occurrence of weather-related and other natural catastrophes. Readers are cautioned that the foregoing list of factors is not exhaustive. Please refer to the annual information form for the year ended December 31, 2025 and the management's discussion and analysis for the three months ended December 31, 2025 for additional risk factors relating to PetroTal, which can be accessed either on PetroTal's website at www.petrotal-corp.com or under the Company's profile on www.sedarplus.ca. The forward-looking statements contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

OIL REFERENCES: All references to "oil" or "crude oil" production, revenue or sales in this press release mean "heavy crude oil" as defined in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

SHORT TERM RESULTS: References in this press release to peak rates, initial production rates, current production rates, 30-day production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of

long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of PetroTal. The Company cautions that such results should be considered to be preliminary.

FOFI DISCLOSURE: This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about PetroTal's prospective results of operations and production results, cash position, liquidity and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this press release was approved by management as of the date of this press release and was included for the purpose of providing further information about PetroTal's anticipated future business operations. PetroTal and its management believe that FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. PetroTal disclaims any intention or obligation to update or revise any FOFI contained in this press release, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein. All FOFI contained in this press release complies with the requirements of Canadian securities legislation, including NI 51-101. Changes in forecast commodity prices, differences in the timing of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in PetroTal's guidance. The Company's actual results may differ materially from these estimates.



CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the interim period ended March 31, 2026

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MANAGEMENT'S REPORT

The accompanying unaudited condensed interim consolidated financial statements and all information in the management discussion and analysis and notes to the unaudited condensed interim consolidated financial statements are the responsibility of management. The unaudited condensed interim consolidated financial statements were prepared by management in accordance with IFRS[®] Accounting Standards, specifically IAS 34, Interim Financial Reporting, as issued by the International Accounting Standards Board ("IASB") outlined in the notes to the unaudited condensed interim consolidated financial statements. Other financial information appearing throughout the report is presented on a basis consistent with the unaudited condensed interim 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 are properly maintained to provide reliable information for the presentation of unaudited condensed interim consolidated financial statements.

The Audit Committee reviewed the unaudited condensed interim consolidated financial statements with management and with the auditors. The Board of Directors has approved the unaudited condensed interim consolidated financial statements on the recommendation of 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

May 06, 2026

CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. \$ - unaudited)

	Note	March 31, 2026	December 31, 2025
ASSETS			
Current			
Cash	4	\$ 104,437	\$ 112,400
Restricted cash	4	14,199	17,039
Trade and other receivables	5	61,946	56,862
Inventory	6	13,473	12,233
Prepaid expenses	7	9,512	10,383
Derivative assets	8	—	967
Total current assets		203,567	209,884
Non-current			
Restricted cash	4	9,691	9,685
Trade and other receivables	5	24,330	24,307
Exploration and evaluation assets	9	11,653	11,410
Property, plant and equipment, net	10	532,902	541,781
Deferred income tax assets	17	1,214	1,077
Prepaid expenses	7	7,000	7,000
Derivative assets	8	1,640	—
Total non-current assets		588,430	595,260
Total assets		\$ 791,997	\$ 805,144
LIABILITIES and EQUITY			
Current			
Trade and other payables	12	\$ 51,416	\$ 58,384
Income tax payables	17	3,732	12,510
Lease liabilities	14	12,908	12,457
Short-term derivative liabilities	8	7,752	—
Short-term debt	11	11,641	11,408
Total current liabilities		87,449	94,759
Non-current			
Long-term debt	11	28,648	31,632
Long-term derivative liabilities	8	—	21,710
Lease liabilities	14	42,448	43,267
Decommissioning liabilities	13	42,886	42,768
Deferred income tax liabilities	17	56,464	53,093
Other long-term liabilities		3,379	2,649
Total non-current liabilities		173,825	195,119
Total liabilities		261,274	289,878
Equity			
Share capital	15	138,228	138,228
Contributed surplus		14,253	14,093
Retained earnings		378,242	362,945
Total equity		530,723	515,266
Total liabilities and equity		\$ 791,997	\$ 805,144

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF EARNINGS AND OTHER COMPREHENSIVE INCOME

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

	Note	Three Months Ended March 31,	
		2026	2025
REVENUES			
Oil revenues, net of royalties and social fund	16	\$ 59,599	\$ 97,710
Total revenues		59,599	97,710
EXPENSES			
Operating		10,928	13,227
Erosion		4,070	1,816
Direct transportation		626	2,300
General and administrative		8,712	9,579
Other income		(50)	—
Net finance expenses		2,016	2,306
Commodity price derivatives (gain) loss	8	(12,897)	1,431
Depletion, depreciation and amortization		18,765	22,137
Foreign exchange (gain) loss		1,092	(417)
Total expenses		33,262	52,379
Income before income taxes		26,337	45,331
Current income tax expense	17	7,806	18,603
Deferred income tax (recovery) expense	17	3,234	(4,124)
Net income and comprehensive income		\$ 15,297	\$ 30,852
Basic		\$ 0.02	\$ 0.03
Diluted		\$ 0.02	\$ 0.03
Weighted average common shares outstanding (in thousands):			
Basic		916,385	915,774
Diluted		928,642	933,424

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

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

	Note	Three Months Ended March 31,	
		2026	2025
Share capital			
Balance, beginning of year		\$ 138,228	\$ 139,198
Repurchase of shares	15	—	(196)
Balance, end of period		\$ 138,228	\$ 139,002
Contributed surplus			
Balance, beginning of year		\$ 14,093	\$ 11,332
Share based compensation plan	15	160	(95)
Balance, end of period		\$ 14,253	\$ 11,237
Retained earnings			
Balance, beginning of year		\$ 362,945	\$ 360,978
Dividends	15	—	(13,828)
Net income and comprehensive income		15,297	30,852
Repurchase of shares	15	—	(355)
Balance, end of period		\$ 378,242	\$ 377,647
Total equity		\$ 530,723	\$ 527,886

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. \$ - unaudited)

		Three Months Ended March 31,	
	Note	2026	2025
Cash flows from operating activities			
Net income		\$ 15,297	\$ 30,852
Adjustments for:			
Depletion, depreciation and amortization		18,765	22,137
Accretion of decommissioning liabilities	13	592	519
Share based compensation plan		890	458
Commodity price unrealized derivative (gain) loss	8	(14,631)	1,431
Net finance expenses		1,809	1,230
Deferred income tax (recovery) expense	17	3,235	(4,124)
Changes in working capital:			
Trade and other receivables		(4,970)	2,237
Prepaid expenses		871	(7,061)
Inventory		(1,240)	2,297
Trade and other payables		(3,967)	(19,435)
Income tax payables	17	8,297	19,291
Cash paid for income taxes		(17,075)	—
Net cash provided by operating activities		7,873	49,832
Cash flows from investing activities			
Property, plant and equipment additions	10	(9,177)	(23,624)
Exploration and evaluation asset additions	9	(243)	(194)
Non-cash changes in working capital		(3,001)	(10,399)
Net cash used in investing activities		(12,421)	(34,217)
Cash flows from financing activities			
Interest and fees paid		(889)	(98)
Repayment of debt principal		(2,810)	—
Dividends paid		—	(13,828)
Repurchase of shares		—	(551)
Payment of current lease liabilities	14	(2,549)	(2,101)
Net cash used in financing activities		(6,248)	(16,578)
Decrease in cash		(10,796)	(963)
Cash, beginning of period		112,400	102,783
Decrease in restricted cash	4	2,834	830
Cash, end of period		\$ 104,438	\$ 102,650

See accompanying notes to the condensed interim consolidated financial statements

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 2026 and 2025.

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 unaudited condensed interim consolidated financial statements (the “Financial Statements”) were approved for issuance by the Company’s Board of Directors on May 6, 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 IFRS[®] Accounting Standards as issued by the International Accounting Standards Board (“IASB”) applicable to the preparation of interim financial statements, including IAS 34, Interim Financial Reporting. They do not contain all disclosures required by IFRS Accounting Standards for annual financial statements and, accordingly, should be read in conjunction with the Company’s audited annual financial statements for the year ended December 31, 2025. Those annual consolidated financial statements outline the Company’s material accounting policies, accounting judgments, and key sources of estimation uncertainty in Note 2, which have been applied consistently in these Financial Statements.

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.

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

	March 31, 2026	December 31, 2025
Cash	\$ 104,437	\$ 112,400
Restricted cash current	14,199	17,039
Restricted cash non-current	9,691	9,685
Total cash and restricted cash	\$ 128,327	\$ 139,124

Current restricted cash of \$14.2 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.

5. TRADE AND OTHER RECEIVABLES

	March 31, 2026	December 31, 2025
Trade receivables	\$ 73,090	\$ 61,586
VAT receivables	12,293	17,980
Other receivables	893	1,603
Total trade and other receivables	\$ 86,276	\$ 81,169
Represented as:		
Current receivables	\$ 61,946	\$ 56,862
Non-current receivables	24,330	24,307
Total trade and other receivables	\$ 86,276	\$ 81,169

Trade receivables represent revenue from the sale of oil. As of March 31, 2026, trade receivables of \$73.1 million consisted of \$46.1 million related to export sales through Brazil and \$27.0 million due from Petroperu. \$52.2 million is expected to be collected within twelve months and is classified as current, with the remaining \$20.9 million classified as non-current. No credit losses have been recognized on the Company's trade receivables as of March 31, 2026 or December 31, 2025.

Value Added Tax ("VAT") in Peru is levied on the purchase of goods and services and is recoverable on the sale of goods and services. During the three months ended March 31, 2026, the Company paid \$3.7 million of VAT on purchases and recovered \$9.4 million through offsets and refunds. The Company expects to recover an additional \$9.4 million of VAT within the next twelve months. By comparison, during the three months ended March 31, 2025, the Company paid \$9.9 million of VAT on purchases and recovered \$13.9 million through offsets and refunds.

6. INVENTORY

	March 31, 2026	December 31, 2025
Materials, parts and supplies	\$ 11,602	\$ 11,092
Oil inventory	1,871	1,141
Total inventory	\$ 13,473	\$ 12,233

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 March 31, 2026, the Company's oil inventory balance was \$1.9 million, representing 47.8 thousand barrels valued at \$39.11 per barrel, compared to \$1.1 million, representing 35.6 thousand barrels at \$32.10 per barrel, as of December 31, 2025.

7. PREPAID EXPENSES

	March 31, 2026	December 31, 2025
Erosion control project advances	\$ 6,491	\$ 7,128
Advances to contractors	7,363	7,401
Prepaid expenses and others	2,658	2,854
Total prepaid expenses	\$ 16,512	\$ 17,383
Represented as:		
Current prepaid expenses	\$ 9,512	\$ 10,383
Non-current prepaid expenses	7,000	7,000
Total prepaid expenses	\$ 16,512	\$ 17,383

As of March 31, 2026, 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 primarily consists of \$1.2 million for rent and \$1.4 million in Peruvian income tax prepayments.

8. RISK MANAGEMENT

	March 31, 2026		December 31, 2025	
	Carrying	Fair Value	Carrying	Fair Value
Cash and restricted cash	\$ 128,327	\$ 128,327	\$ 139,124	\$ 139,124
Trade and other receivables	52,155	52,155	41,878	41,878
Short-term derivative assets	—	—	967	967
Trade receivable long-term	21,430	21,430	21,311	21,311
Long-term derivative assets	1,640	1,640	—	—
Short-term derivative liabilities	7,752	7,752	—	—
Short and long-term debt	40,289	40,289	43,040	43,040
Trade and other payables	51,416	51,416	58,384	58,384
Long-term derivative liabilities	—	—	21,710	21,710

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 March 31, 2026 and March 31, 2025.

	Three Months Ended March 31,	
	2026	2025
Net derivative liability at beginning of period	\$ (20,743)	\$ (8,916)
Cash settlements to be paid	1,810	—
Cash settlements received	(77)	—
Realized loss	(1,733)	—
Unrealized gain (loss)	14,631	(1,431)
Net derivative liability at end of period	\$ (6,112)	\$ (10,347)

	March 31,	December 31,
	2026	2025
Short-term derivative assets	\$ —	\$ 967
Long-term derivative assets	1,640	—
Short-term derivative liabilities	(7,752)	—
Long-term derivative liabilities	—	(21,710)
Net derivative liability at end of period	\$ (6,112)	\$ (20,743)

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	\$75.21 to \$76.50	\$ 1,640
Corporate Derivatives Hedging ⁽²⁾					
Jan-25 to March-27	Apr-26 to Mar-27	1,356	—	\$55.00 to \$93.75	(7,752)
Net derivative liability					\$ (6,112)

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

As of March 31, 2026 and December 31, 2025, approximately 1.9 million barrels remain in the pipeline or storage tanks, awaiting final sale by Petroperu. During Q1 2026, an increase in future oil prices related to the Peru embedded derivative resulted in a gain. The net result is a net asset of \$1.6 million as of March 31, 2026 versus a net liability of \$21.7 million as of December 31, 2025. 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 asset. Derivative gains and losses are only realized when oil is effectively sold to third parties at Bayovar.

⁽²⁾ Corporate Hedge Program

During Q1 2026, the Company expanded its hedging program by entering into Brent oil contracts for 1.4 million barrels. These new positions consist of four three-way collars with the following strike price ranges:

Put Price (Floor): \$55.00 to \$65.00/bbl.

Call Price (Ceiling): \$72.10 to 73.75/bbl.

Call Ceiling Price (Cap): \$92.10 to \$93.75/bbl.

As of March 31, 2026, the fair value of these derivative instruments was recognized as a net liability of \$7.8 million.

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 three months ended March 31, 2026, PetroTal sold substantially all of its oil through two primary routes: 97.6% via the Brazil export route, and 2.4% to the local Iquitos refinery. Sales via the ONP remained inactive during the period, while sales to the local Iquitos refinery continued throughout Q1 2026. 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 financial institutions. The maximum credit exposure associated with financial assets is their carrying value. As of March 31, 2026, 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, 2025	\$ 10,406
Additions	1,004
Balance at December 31, 2025	\$ 11,410
Additions	243
Balance at March 31, 2026	\$ 11,653

Exploration and evaluation ("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 March 31, 2026 and December 31, 2025, 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, 2025	\$ 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
Additions	9,177	1,183	—	10,360
Revisions to decommissioning obligations	(474)	—	—	(474)
Depletion, depreciation and amortization	(17,410)	(946)	(409)	(18,765)
Balance at March 31, 2026	\$ 466,633	\$ 61,354	\$ 4,915	\$ 532,902

Depreciation, depletion and amortization expenses included in inventory were immaterial as of March 31, 2026 and December 31, 2025. As of March 31, 2026, there were no indicators of impairment.

11. DEBT

	March 31, 2026	December 31, 2025
Short-term debt	\$ 11,641	\$ 11,408
Long-term debt	28,648	31,632
Total debt	\$ 40,289	\$ 43,040

As of March 31, 2026, the Company had \$40.3 million outstanding under the loan related to the erosion control project, of which \$11.6 million was classified as short-term and \$28.6 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.

The Company has \$30.0 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 March 31, 2026, 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 March 31, 2026:

Year		
2026	\$	8,657
2027		12,307
2028		13,396
2029		5,929
Total	\$	40,289

12. TRADE AND OTHER PAYABLES

	March 31, 2026	December 31, 2025
Trade payables	\$ 15,812	\$ 19,501
Accrued payables and other obligations	35,604	38,883
Total trade and other payables	\$ 51,416	\$ 58,384

As of March 31, 2026 and December 31, 2025, 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 period reflected lower drilling activity. Other obligations were mainly related to the 2.5% social fund for the benefit of local communities, which totaled \$0.5 million and \$0.2 million as of March 31, 2026 and December 31, 2025, respectively. The increase in the social fund balance as of March 31, 2026 primarily reflects accruals made during the quarter. 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 \$71.4 million as of March 31, 2026 and December 31, 2025, respectively. The present value of the liabilities was calculated using average risk-free rates between 5.3% to 5.8% as of March 31, 2026 and 5.3% to 5.7% as of December 31, 2025, 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.

	Decommissioning Liabilities
Balance at January 1, 2025	\$ 34,383
Revisions to decommissioning liabilities	6,232
Accretion of decommissioning liabilities	2,153
Balance at December 31, 2025	\$ 42,768
Revisions to decommissioning liabilities	(474)
Accretion of decommissioning liabilities	592
Balance at March 31, 2026	\$ 42,886

14. LEASE LIABILITIES

The lease liabilities related to drilling, power generation equipment and office premises in Houston, Texas and Lima, Peru, with lease terms ranging from 2 to 5 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 of 2025, an additional \$2.3 million increase in lease liabilities was recorded related to commissioning activities of the drilling rig lease. The incremental borrowing

rate used to measure the lease liability was 8.65%, and the lease term extends to February 2030.

Lease liabilities at January 1, 2025	\$	54,641
Additions		6,563
Revisions		25
Payments		(10,061)
Interest on leases		4,556
Lease liabilities at December 31, 2025	\$	55,724
Additions		1,183
Payments		(2,549)
Interest on leases		998
Lease liabilities at March 31, 2026	\$	55,356
Represented as:		
Current liability	\$	12,908
Non-current liability		42,448
Total lease liabilities	\$	55,356

The following is a summary of minimum undiscounted annual lease payments by year as of March 31, 2026:

Year		
2026	\$	11,619
2027		15,042
2028		14,480
2029		9,606
2030		6,961
Thereafter		7,451
Total	\$	65,159

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, 2025	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
Vesting of performance share units	7,352	—
Repurchase of shares	—	—
Balance at March 31, 2026	920,328 \$	138,228

DIVIDENDS

The Company suspended its dividend policy in November 2025. As such, the company paid no dividends to shareholders in Q1 2026 and \$13.8 million (\$0.015 per share) in Q1 2025. The Company paid dividends of \$42.2 million 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 March 31, 2026. 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 three months ended March 31, 2026 the Company did not purchase any shares under the NCIB. During the three months ended March 31, 2025, the Company purchased 1.2 million common shares for total consideration of \$0.6 million. 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 deferred share units (“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 key performance indicators (“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 March 31, 2026:

	Performance Share Units	Deferred Share Units
Balance at January 1, 2025	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
Additions	—	485,075
Forfeited	(1,344,038)	—
Balance at March 31, 2026	14,563,862	7,879,036

The Company recognized \$1.6 million and \$1.1 million of share-based compensation expense during the three months ended March 31, 2026 and 2025, respectively, which is included in general and administrative expenses in the Condensed Interim 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.

	Three Months Ended March 31,	
	2026	2025
Oil revenue	\$ 65,950	\$ 109,951
Royalty	(4,537)	(9,554)
Social fund	(1,814)	(2,687)
Total oil revenue net of royalties and social fund	\$ 59,599	\$ 97,710

The Company sold 1.3 million and 2.1 million barrels of oil during the three months ended March 31, 2026 and 2025, respectively, at a net realized sales price of \$51.07 per barrel and \$52.46 per barrel, respectively, net of price discounts.

17. 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:

	Three Months Ended March 31,	
	2026	2025
Earnings before income taxes	\$ 26,337	\$ 45,331
Canadian corporate tax rate	23%	23%
Expected income tax expense	\$ 6,057	\$ 10,426
Increase (decrease) in taxes resulting from:		
Non-deductible expenses and other	3,739	726
Tax differential on foreign jurisdictions	2,385	3,327
Change in valuation allowance and NOL reduction	(1,141)	—
Provision for income taxes	\$ 11,040	\$ 14,479

The Company recognized the deferred tax assets and deferred tax liabilities in Canada, Peru, and the U.S arising from temporary differences. During 2025, the Company exhausted all net operating losses ("NOLs") in the U.S. and all non-capital losses in Canada. As such, there are no NOLs to utilize in 2026.

Ucawa has \$94.3 million in tax losses as of March 31, 2026, compared to \$96.1 million as of December 31, 2025 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 March 31, 2026, the aggregate amount of temporary differences related to investments in subsidiaries for which deferred tax liabilities have not been recognized was approximately \$15.2 million, compared to \$56.4

million as of December 31, 2025.

18. COMMITMENTS AND CONTINGENCIES

As of March 31, 2026, 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. At the end of Q1 2026, the agreement with the contractors, the EBD Consortium, was canceled and the company is currently seeking a replacement.

As part of the 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, CEPESA S.A., is obligated to indemnify PetroTal against any related legal action and/or fines, if applicable.

19. 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 continues to evaluate options to dispose of the drilling rig.



MANAGEMENT'S DISCUSSION AND ANALYSIS

For the interim period ended March 31, 2026

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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 period ended March 31, 2026 is dated May 6, 2026, and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements (the "Financial Statements") for the period ended March 31, 2026. The 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's key operational and financial performance levels are described below:

Operational Highlights

- Oil production was 1.3 million bbls, an average of 14,907 bopd in Q1 2026, a decrease of 2% from 1.4 million bbls, an average of 15,258 bopd in Q4 2025. As of March 31, 2026, the Company had 24 producing oil wells and 4 water disposal wells; and,
- Oil sales allocations were all directed through two primary routes: 97.6% to exports through Brazil and 2.4% to the Iquitos refinery.

Financial Highlights

- Revenue totaled \$65.9 million in Q1 2026, based on 1.3 million bbls sold, (average 14,350 bopd) at an average realized price of \$51.07/bbl, compared to \$55.0 million from 1.4 million bbls sold (average 15,059 bopd) at an average realized price of \$39.67/bbl in Q4 2025. Of the \$65.9 million in revenue, \$50.7 million corresponds to Bretana;
- Royalties paid to the Peruvian government in Q1 2026 totaled \$4.5 million (\$3.51/bbl, 6.9% of revenues) compared to \$6.6 million (\$4.78/bbl, 12.0% of revenues) in Q4 2025. Of the \$4.5 million in royalties, \$4.2 million is related to Bretana. Contributions to the 2.5% community social trust fund were \$1.8 million in Q1 2026, as compared to \$2.1 million in Q4 2025;
- Capital expenditures ("capex") were incurred totaling \$7.6 million in Q1 2026, primarily related to field infrastructure, and the erosion project;
- EBITDA and Free funds flow for Q1 2026 were \$35.3 million (\$27.34/bbl) and \$25.7 million (\$19.92/bbl), respectively, compared to \$16.4 million (\$11.83/bbl) and \$3.3 million (\$2.35/bbl) in Q4 2025, respectively;
- Net operating income totaled \$48.0 million (\$37.21/bbl) in Q1 2026, compared to \$25.3 million (\$18.30/bbl) in Q4 2025;
- Cash position at the end of Q1 2026 was \$128.3 million, including \$104.4 million of unrestricted cash, compared to \$139.1 million, including \$112.4 million of unrestricted cash at the end of 2025;
- Restricted cash of \$23.9 million at the end of Q1 2026 was associated with the COFIDE and BanBif loan designated for use in the erosion control project and permitted hedging programs, compared to \$26.7 million at the end of 2025; and,
- The Company suspended its dividend policy in November 2025. It did not pay dividends or repurchase shares in Q1 2026. In Q4 2025, no dividends were paid and 0.4 million shares were repurchased for \$0.2 million.

3. SELECTED FINANCIAL INFORMATION

3.1 FINANCIAL SUMMARY

(\$ thousands)	Q1-2026		Q4-2025		Q3-2025		Q2-2025			
	\$/bbl		\$/bbl		\$/bbl		\$/bbl			
PRODUCTION:	Average production (bopd)		14,907		15,258		18,414		21,039	
SALES:	Average sales (bopd)		14,350		15,059		18,028		20,578	
	Total sales (bbls)		1,291,473		1,385,460		1,658,621		1,872,602	
	Average Brent price	\$ 74.65	\$ 62.46	\$ 66.96	\$ 65.55					
	Weighted contracted sales price, gross	74.50	62.49	66.95	65.53					
LESS:	Tariffs, fees and differentials		(23.43)		(22.82)		(23.62)		(22.75)	
	Realized sales price, net		51.07		39.67		43.33		42.78	
REVENUES:	Oil revenue ⁽¹⁾	\$ 51.07	\$ 65,950	\$ 39.67	\$ 54,959	\$ 43.33	\$ 71,871	\$ 42.78	\$ 80,110	
LESS:	Royalties ⁽²⁾		4.92 6,351		6.32 8,759		4.80 7,961		4.95 9,276	
	Operating expenses (excluding erosion)		8.46 10,928		14.35 19,883		8.34 13,834		9.34 17,488	
	Direct transportation:									
	Barging	0.48	626	0.48	670	0.60	1,003	0.79	1,482	
	Dry Season Freight/Storage/Inventory	—	—	0.22	301	2.76	4,579	0.30	570	
	Total transportation	0.48	626	0.70	971	3.36	5,582	1.09	2,052	
NET OPERATING INCOME ("NOI")	37.21 48,045		18.30 25,346		26.83 44,494		27.40 51,294			
	NOI as % of Revenue		73 %		46 %		62 %		64 %	
	Erosion expense	3.15	4,070	2.95	4,083	3.91	6,481	0.38	705	
	General and administrative expense	6.75	8,712	3.52	4,877	4.38	7,271	4.15	7,775	
	Commodity price derivative loss (gain)	(9.99)	(12,897)	4.95	6,853	1.26	2,082	(0.19)	(361)	
	Net financial expenses	1.56	2,016	1.71	2,369	1.08	1,789	0.29	535	
	Income tax expense (recovery)	8.55	11,040	(2.71)	(3,753)	2.45	4,069	1.92	3,595	
	Depletion, depreciation and amortization expense	14.53	18,765	14.15	19,607	11.56	19,168	11.78	22,053	
	Other income	(0.04)	(50)	—	—	—	—	—	—	
	Foreign exchange (gain) loss	0.85	1,092	(0.66)	(913)	0.02	35	(0.28)	(521)	
NET INCOME (LOSS)	15,297		(7,777)		3,599		17,513			
FREE FUNDS FLOW	\$19.92	\$ 25,728	\$2.35	\$ 3,257	\$7.17	\$ 11,886	\$14.55	\$ 27,246		

⁽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.

(\$ thousands)	Q1-2025		Q4-2024		Q3-2024		Q2-2024			
	\$/bbl		\$/bbl		\$/bbl		\$/bbl			
PRODUCTION:	Average production (bopd)		23,281		19,142		15,203		18,290	
SALES:	Average sales (bopd)		23,286		19,087		14,760		18,050	
	Total sales (bbls)		2,095,714		1,756,030		1,357,961		1,642,578	
	Average Brent price	\$ 73.96	\$ 73.42	\$ 77.74	\$ 83.87					
	Weighted contracted sales price, gross	73.89	73.16	78.58	83.92					
LESS:	Tariffs, fees and differentials		(21.43)		(21.10)		(20.52)		(21.15)	
	Realized sales price, net		52.46		52.06		58.06		62.76	
REVENUES:	Oil revenue ⁽¹⁾	\$ 52.46	\$ 109,951	\$ 52.06	\$ 91,421	\$ 58.06	\$ 78,850	\$ 62.76	\$ 103,086	
LESS:	Royalties ⁽²⁾	5.84	12,241	7.42	13,022	5.47	7,433	6.08	9,991	
	Operating expenses (excluding erosion)	6.31	13,227	7.88	13,843	8.23	11,176	6.10	10,023	
	Direct transportation:									
	Diluent	—	—	0.14	248	0.90	1,218	1.16	1,898	
	Barging	0.79	1,664	1.94	3,398	0.81	1,100	0.69	1,137	
	Dry Season Freight/Storage/Inventory	0.30	636	1.97	3,452	0.51	690	0.01	12	
	Total transportation	1.09	2,300	4.05	7,098	2.22	3,008	1.86	3,047	
NET OPERATING INCOME (NOI)		39.22	82,183	32.71	57,458	42.14	57,233	48.72	80,025	
	NOI as % of Revenue		75 %		63 %		73 %		78 %	
	Erosion expense	0.87	1,816	5.45	9,569	0.40	548	—	—	
	General and administrative expense	4.57	9,579	4.86	8,534	6.75	9,160	6.41	10,528	
	Commodity price derivative loss (gain)	0.68	1,431	(1.55)	(2,726)	15.82	21,481	2.01	3,306	
	Net financial expenses (income)	1.10	2,306	1.19	2,096	(0.23)	(311)	0.62	1,018	
	Income tax expense (recovery)	6.91	14,479	(0.12)	(209)	4.45	6,038	8.81	14,471	
	Depletion, depreciation and amortization	10.56	22,137	10.54	18,504	9.64	13,092	9.32	15,311	
	Foreign exchange loss (gain)	(0.20)	(417)	0.25	448	0.03	46	(0.01)	(14)	
NET INCOME			30,852		21,242		7,179		35,405	
FREE FUNDS FLOW		\$22.92	\$ 48,042	(\$5.93)	\$ (10,422)	\$4.81	\$ 6,537	\$22.12	\$ 36,334	

⁽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.

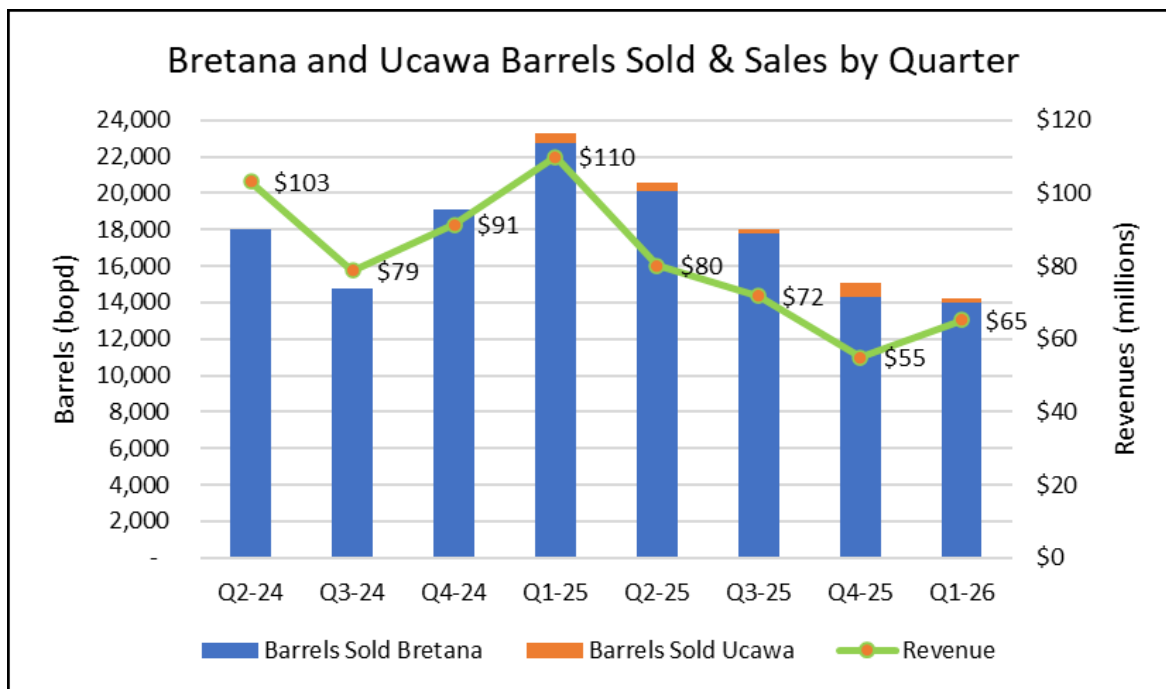
EARNINGS STATEMENT INFORMATION

Oil sales in Q1 2026 decreased by 7% to 1.3 million bbls (average 14,350 bopd), compared to 1.4 million bbls (average 15,059 bopd) in Q4 2025. Sales decreased 38% in Q1 2026 compared to 2.1 million bbls (average 23,286 bopd) in Q1 2025.

The Company may sell oil through three sales points: the local Iquitos refinery, exports through Brazil, and the Northern Peruvian Pipeline ("ONP"). In Q1 2026, PetroTal directed 97.6% of total production to export markets through Brazil, transitioning 100% of Bretana crude to export routes to mitigate regional offtake and counterparty risks. The remaining 2.4%, sourced from the Los Angeles field, continued to supply the Iquitos refinery under rigorous counterparty credit and payment monitoring. 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 \$6.4 million (\$4.92/bbl) in Q1 2026 from \$8.8 million (\$6.32/bbl) in Q4 2025, and decreased from \$12.2 million (\$5.84/bbl) in Q1 2025. 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 \$10.9 million (\$8.46/bbl) in Q1 2026, compared to \$19.9 million (\$14.35/bbl) in Q4 2025, and \$13.2 million (\$6.31/bbl) in Q1 2025. The quarter-over-quarter decrease reflects the completion of several non-recurring activities in Q4 2025, including well pulling operations, QHSE campaigns, and higher contract service costs (laboratory, camp, maintenance, and operations). As a result, Q1 2026 reflects a lower level of activity and associated costs following the higher spending in the prior quarter.

Erosion expenses in Q1 2026 totaled \$4.1 million (\$3.15/bbl) compared to \$4.1 million (\$2.95/bbl) in Q4 2025, reflecting no material variance quarter-over-quarter, and \$1.8 million (\$0.87/bbl) in Q1 2025. The increase versus Q1 2025 is primarily driven by contractor equipment demobilization and other costs associated with the termination of the EBD Consortium agreement.

Direct transportation expenses in Q1 2026 totaled \$0.6 million (\$0.48/bbl) compared to \$1.0 million (\$0.70/bbl) in Q4 2025. This sequential decline was primarily driven by lower crude sales and volumes. On the year-over-year basis, expenses fell from \$2.3 million (\$1.09/bbl) in Q1 2025, a reduction largely attributed to the elimination of demurrage claims, which reached zero in the current quarter.

General and administrative ("G&A") expenses in Q1 2026 totaled \$8.7 million (\$6.75/bbl) compared to \$4.9 million (\$3.52/bbl) in Q4 2025, and \$9.6 million (\$4.57/bbl) in Q1 2025. The Q1 2026 over Q1 2025 improvement was primarily driven by lower advisory and consulting requirements following the successful integration of Ucawa. The Q1 2026 over Q4 2025 \$3.8 million variance is attributed to higher personnel-related accruals.

Net finance expenses totaled \$2.0 million (\$1.56/bbl) in Q1 2026 compared to \$2.4 million (\$1.71/bbl) in Q4 2025, and \$2.3 million (\$1.10/bbl) in Q1 2025. This decrease from prior periods was primarily driven by the revision of the decommissioning obligations.

Commodity price derivative gain for Q1 2026 was \$12.9 million (\$9.99/bbl) compared to a loss of \$6.9 million (\$4.95/bbl) in Q4 2025, and a loss of \$1.4 million (\$0.68/bbl) in Q1 2025. This gain represents the combined net fair value change of outstanding embedded derivatives and hedging contracts. 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 Q1 2026 were \$18.8 million (\$14.53/bbl) compared to \$19.6 million (\$14.15/bbl) in Q4 2025, and \$22.1 million (\$10.56/bbl) in Q1 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 loss in Q1 2026 was \$1.1 million (\$0.85/bbl) compared to a gain of \$0.9 million (\$0.66/bbl) in Q4 2025, and a gain of \$0.4 million (\$0.20/bbl) in Q1 2025, primarily due to fluctuations in currency positions and transactional exposures.

Income tax expense in Q1 2026 was \$11.0 million (\$8.55/bbl) compared to a benefit of \$3.8 million (\$2.71)/bbl) in Q4 2025, and an expense of \$14.5 million (\$6.91/bbl) in Q1 2025. The increase was primarily driven by exhausting our NOLs during 2025 and higher oil prices.

3.2 SELECTED BALANCE SHEET INFORMATION

Liquidity and capital resources

As of March 31, 2026, the Company held cash of \$104.4 million and restricted cash of \$23.9 million, totaling \$128.3 million, compared to held cash of \$112.4 million and restricted cash of \$26.7 million, totaling \$139.1 million as of December 31, 2025. Working capital was \$116.1 million as of March 31, 2026, compared to \$115.1 million as of December 31, 2025, reflecting lower cash balances and higher current liabilities at March 31, 2026.

Current restricted cash of \$14.2 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

	Three Months Ended March 31,	
	2026	2025
Drilling Program	\$ 380	\$ 13,833
Field Infrastructure	5,447	5,747
Fluid Handling Facilities ("CPF")	—	2,313
Erosion Costs	1,626	—
Block 95	96	812
Block 107	(4)	188
Other	77	596
Exploration & development expenditures	7,622	23,489
SAP Project	—	135
Total capital expenditures	\$ 7,622	\$ 23,624

PetroTal invested \$7.6 million in petroleum capital expenditures for three months ended March 31, 2026, compared to \$23.5 million for three months ended March 31, 2025. The decrease is primarily caused by lower drilling activity and fluid handling facilities during the quarter, partially offset by an increase in the erosion project.

As of March 31, 2026, the Company had \$11.7 million in exploration and evaluation assets related to Block 95 and Block 107.

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 May 6, 2026, PetroTal has the following securities outstanding (in thousands):

Common shares	920,328	98%
Performance share units	14,564	2%
Total	934,892	100%

Dividends

The Company did not pay dividends during the three months ended March 31, 2026. During the three months ended March 31, 2025, the Company paid dividends to shareholders of \$13.8 million (\$0.015 per share).

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 March 31, 2026. 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.

The Company did not purchase common shares during the three months ended March 31, 2026. The Company purchased 1.2 million common shares under the NCIB for total consideration of \$0.6 million during the three months ended March 31, 2025. The surplus between the total consideration and the carrying value of the shares repurchased was recorded against retained earnings.

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		
	March 31, 2026	December 31, 2025	March 31, 2025
Cash flow from operating activities			
Net (loss) income	\$ 15,297	\$ (7,777)	\$ 30,852
Adjustments for:			
Depletion, depreciation and amortization	18,765	19,607	22,137
Accretion of decommissioning obligation	592	560	519
Share based compensation plan	890	650	458
Net finance expenses	1,809	1,990	1,230
Deferred income tax expense (recovery)	3,235	(6,359)	(4,124)
Commodity price unrealized derivatives (gain) loss	(14,631)	8,361	1,431
Funds flow provided by operations before non-cash working capital	\$ 25,957	\$ 17,032	\$ 52,503
Changes in non-cash working capital:			
Trade and other receivables	(4,970)	840	2,237
Prepaid expenses	871	2,169	(7,061)
Inventory	(1,240)	(216)	2,297
Income tax payable	(3,967)	14	(19,435)
Trade and other payables	8,297	2,589	19,291
Cash paid for income taxes	(17,075)	(3,905)	—
Net cash provided by operating activities	\$ 7,873	\$ 18,522	\$ 49,832
Cash flow from investing activities			
Exploration and evaluation asset additions	\$ (243)	\$ (353)	\$ (194)
Property, plant and equipment additions	(9,177)	(14,933)	(23,624)
Non-cash changes in working capital	(3,001)	906	(10,399)
Net cash used in investing activities	(12,421)	(14,380)	(34,217)
Net cash provided by (used in) operating and investing activities	\$ (4,548)	\$ 4,142	\$ 15,615

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		
	March 31, 2026	December 31, 2025	March 31, 2025
Net (loss) income	\$ 15,297	\$ (7,777)	\$ 30,852
Adjustments to reconcile net income:			
Depletion, depreciation and amortization	18,765	19,607	22,137
Net finance expenses	2,016	2,369	2,306
Income tax expense (recovery)	11,040	(3,753)	14,479
Commodity price derivatives (gain) loss	(12,897)	6,853	1,431
Foreign exchange (gain) loss	1,092	(913)	(417)
EBITDA (non-GAAP)	\$ 35,313	\$ 16,386	\$ 70,788
Commodity price derivatives realized gain (loss)	(1,733)	1,507	—
Share based compensation plan	1,568	650	1,072
Adjusted EBITDA (non-GAAP)	\$ 35,148	\$ 18,543	\$ 71,860
Capital expenditures	(9,420)	(15,286)	(23,624)
Free funds flow (non-GAAP)	\$ 25,728	\$ 3,257	\$ 48,236

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. SIGNIFICANT JUDGMENTS AND ESTIMATES

The preparation of the Company's Financial Statements requires management to make judgments, assumptions, and estimates that affect the reported amounts of assets, liabilities, income, and expenses. Critical accounting policies relate to areas where these judgments and estimates have the most significant impact on the Financial Statements. There have been no material changes to the Company's critical accounting policies or estimates since the filing of the Annual Financial Statements. For a detailed discussion of the Company's significant accounting policies, critical judgments, and estimates—including assumptions and measurement uncertainties—refer to the annual financial statements and notes for the year ended December 31, 2025.

5. 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 2027 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 the Canadian Oil and Gas Evaluation Handbook ("COGE") 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. 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

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AIM: PTAL

OTCQX Stock Exchange
New York, USA
OTCQX: PTALF

LEGAL COUNSEL

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JOINT BROKERS

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RESERVES EVALUATORS

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

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada
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⁽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