2022 YEAR END REPORTING PACKAGE

MARCH 30, 2023

TSX:TAL
AIM: PTAL
OTCQX: PTALF

PetroTal Announces 2022 Year-End Financial and Operating Results

Delivered annual average production of 12,200 bopd representing a 36% growth rate over 2021
Increased 2022 2P reserves to 97 million barrels (24%) and after tax NPV-10 to US$1.75/share (46%)
Established a new record production level of over 26,000 bopd
Generated 2022 free funds flow of $162 million (~38% of exit 2022 market capitalization)
Brought four highly productive horizontal oil wells online in 2022 to exit the year with 20,000 bopd
Bonds now fully repaid and return of capital program announced subsequent to 2022 year-end

Calgary, AB and Houston, TX – **March 30, 2023**—PetroTal Corp. ("**PetroTal**" or the "**Company**") (TSX: TAL, AIM: PTAL and OTCQX: PTALF) is pleased to report its operating and audited financial results for the three months ("Q4") and year ended December 31, 2022.

Select financial, reserves and operational information is outlined below and should be read in conjunction with the Company's audited consolidated financial statements ("Financial Statements"), management's discussion and analysis ("MD&A") and annual information form ("AIF") for the year ended December 31, 2022, which are available on SEDAR at www.sedar.com and on the Company's website at www.PetroTal-Corp.com. Reserves numbers presented herein were derived from an independent reserves report ("NSAI Report") prepared by Netherland, Sewell & Associates, Inc. ("NSAI") effective December 31, 2022. All amounts herein are in United States dollars ("USD") unless otherwise stated.

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

"I am proud of our performance in 2022, a year in which the Company was resilient despite facing a number of challenges. We are pleased with 2022's operational and financial results, having significantly improved the operating stability of the Company in recent months from both a sales and balance sheet perspective. In addition, it was equally important that we fulfilled our promise to investors to fully repay our bonds and initiating a return of capital program to our patient and deserving shareholder group.

In closing, I would like to thank our shareholders for their continued support, the PetroTal team for their considerable contributions to the Company, and our Board for strategic guidance."

2022 Key Milestones and Highlights

- Achieved average annual production and sales of 12,200 and 13,168 barrels of oil per day ("bopd") respectively, up 36% and 56% from 2021;

- Delivered a 46% increase in 2P reserves value per share (NPV-10, after tax) to US$1.75/share (CAD$2.29 and GBP1.45), and a 24% increase in 2P reserves to 96.8 million barrels;

- Provided strong 2022 year-end 1P and 2P reserve replacement ratios of 179% and 418%, respectively;

- Set a record for daily production of over 26,000 bopd on June 30, 2022 confirming the current facility oil handling capacity;

- Drilled and completed four new highly productive horizontal oil wells in 2022 with average productivity indexes of approximately 37.5 barrels per pound of drawdown. With a relatively small pressure drawdown of 280 pounds, each well could produce more than 10,000 bopd for a period of time as showcased by the 10H and 11H wells;

- During well 13H's drilling operation the technical team encountered the target producing formation approximately three meters higher than prognosis which contributed to oil-in-place and reserves upgrades in the 2022 year-end reserve report;

- Generated record annual net operating income ("NOI") of $274 million ($56.90/bbl) and adjusted EBITDA inclusive of realized derivative impacts, of $256 million ($53.28/bbl);

- 2022 free funds flow totalled $161.9 million, prior to working capital adjustments and debt service, and after $94.2 million in total capital expenditures. This equates to a 38% free funds flow yield using the December 31, 2022 market capitalization and was approximately $33.66/bbl;

- Announced in September 2022, Messrs. Luis Carranza and Jon Harris were elected as directors for the Company following the retirement of Messrs. Gary Guidry and Ryan Ellson; and,

- Exited 2022 with approximately $120 million in cash ($15.6 million restricted) and a $74 million net surplus on the balance sheet allowing for full bond repayment subsequent to December 31, 2022.

Selected Q4 2022 and 2022 Financial and Operational Highlights

(in thousands USD)		Three Months Ended			Twelve Months Ended	
		Dec 31, 2022	Dec 31, 2021		Dec 31, 2022	Dec 31, 2021
Average Production	**Bopd**	**10,374**	**10,147**		**12,200**	**8,966**
Average Sales	**"**	**10,420**	**7,242**		**13,168**	**8,449**
Average Brent ICE Price	$/bbl	$88.61	$79.79		$98.92	$70.82
Contracted Sales Price[1]	"	$88.22	$77.46		$96.67	$68.22
Tariffs, fees, and differentials	"	($21.71)	($18.56)		($21.96)	($16.60)
Realized Sales Price	**"**	**$66.51**	**$58.90**		**$74.71**	**$51.62**
Royalties[2]	"	($6.08)	($3.46)		($6.66)	($2.91)
Lifting	"	($7.42)	($7.60)		($6.86)	($6.99)
Direct Transportation	"	($2.50)	($9.23)		($4.29)	($7.69)
Netback[3]	**"**	**$50.51**	**$38.61**		**$56.90**	**$34.03**
Net Operating Income		$48,422	$25,727		$273,539	$104,960
Adjusted EBITDA[4]		**$36,338**	**$11,887**		**$256,069**	**$101,974**
Net Income		$37,176	$6,844		$188,527	$63,972
Basic Shares Outstanding	000's	862,209	828,197		862,209	828,197
Market Capitalization[5]		$431,104	$273,305		$431,104	$273,305
Net Income/share	$/share	$0.04	$0.01		$0.22	$0.08
Capex		$32,024	$26,601		$94,202	$82,191
Free funds Flow[6]		**$4,314**	**($14,714)**		**$161,867**	**$19,783**
% of Market Capitalization		0.1%	(5.4%)		37.5%	7.2%
Total Cash[7]		**$119,969**	**$74,459**		**$119,969**	**$74,459**
Net Surplus (Debt)[8]		**$74,225**	**($56,076)**		**$74,225**	**($56,076)**

1. Approximately 71% of sales in 2022 were through the Brazilian route vs 27% in 2021.
2. Royalties in Q3 and Q4 2022 include the impact of the 2.5% community social trust retroactive to the beginning of 2022.
3. Netback per barrel ("bbl") does not have standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures for other entities. See "Selected Financial Measures" section.
4. Adjusted EBITDA is Net Operating Income less G&A and plus/minus realized derivative impacts. See "Selected Financial Measures" section.
5. Market capitalization for 2022 and 2021 assume share prices of $0.50 and $0.33, respectively.
6. Free funds flow is defined as adjusted EBITDA less capital expenditures.
7. Includes restricted cash balances.
8. Net Surplus/Debt = Total cash + all trade and VAT receivables + short and long term net derivative balances – total current liabilities – long term debt – non current lease liabilities – deferred tax – other long term obligations.

Selected Q4 2022 and FY 2022 Financial and Operating Highlights

Production and sales. Production and sales for the quarter averaged 10,374 and 10,420 bopd respectively. Production was significantly constrained during October and November 2022 due to low river levels and a river blockade, however, the Company was able to produce an average of 20,766 bopd during the last two weeks in December once these two issues were resolved which allowed quarterly production to average above 10,000 bopd.

Net Revenue profile. Oil revenue in Q4 2022, net of tariffs, fees, and differentials was $63.8 million ($66.51/bbl) compared to Q3 2022 of $84.2 million ($75.07/bbl) and Q4 2021 of $39.2 million ($58.9/bbl).

High margin operational cash flow. Generated Q4 2022 NOI and Adjusted EBITDA of $48.4 million ($50.51/bbl) and $36.3 million ($37.87/bbl), respectively, compared to $62.3 million ($55.58/bbl) and $84.2 million ($75.10/bbl), respectively, in Q3 2022 and $25.7 million ($38.61/bbl) and $11.9 million ($17.84/bbl), respectively, in Q4 2021. Net operating income for 2022 represents a 57% margin on contracted gross sales revenue allowing sufficient margin to fund CAPEX, G&A and debt service.

Capital expenditures. Capital deployed in Q4 2022 totalled $32.0 million, of which approximately 65% was allocated to drilling and completing wells 12H and 13H and commencing drilling on the Company's next water disposal well, 4WD. For the year ended December 31, 2022, the Company invested a total of $94.2 million in capital expenditures, a $12.1 million (15%) increase from 2021, driving a 36% increase in year-over-year production.

Substantial Net income. PetroTal posted Q4 2022 net income of $37.2 million, making Q4 2022 the 12th quarter in a row with positive net income. Net income for the year ended 2022 was $188.5 million ($0.22/share) and approximately 44% of PetroTal's exit 2022 market capitalization.

Solid balance sheet metrics allowing flexible capital allocation. Year-end 2022 short and long term debt was $81.4 million including accrued interest payable generating an exit debt to 2022 adjusted EBITDA ratio of 0.3x. Including working capital and cash, the Company exited 2022 with a net surplus of $74.2 million or approximately 17% of the Company's market capitalization at year-end 2022.

Net derivative asset balance. The total net derivative asset on the balance sheet as at December 31, 2022 was $20.4 million, an increase of $16.8 million from Q3 2022, driven by mark-to-market changes in the value of oil in the Northern Peruvian Oil Pipeline ("ONP"). As at December 31, 2022 approximately 2.4 million barrels remained in the ONP with an average cost base of approximately $70/bbl.

Petroperu payment schedule finalized to reduce receivable balances. During Q4 2022, PetroTal and Petroperu finalized a repayment agreement for the $64 million in true-up revenue owed to the Company by Petroperu from a July 2022 oil export of 720,000 barrels. As at March 1, 2023 the Company has received nearly $27 million (40%) in accordance with the scheduled payments.

Robust production from wells 13H and 12H. Well 13H was drilled and completed in late Q3/early Q4 2022 and generated an initial peak production rate of 8,000 bopd during its first week of production. The drilling team encountered the target formation approximately three meters higher than prognosis which positively impacted 2022 year-end reserves and oil-in-place estimates. Well 12H was completed and tested around December 16, 2022, however due to export constraints the well's pump was not activated to constrain higher production rates until mid Q1 2023.

Financial and Operating Highlights Subsequent to December 31, 2022

Continuous development to increase production. Drilling commencement of drilling 14H began on February 8, 2023 following the successful drilling and coring of the Company's third water disposal well on January 29, 2023. Well 14H will be the longest horizontal well ever drilled in Peru with a total measured depth of around 5,135 meters. The well took 38 days to drill and encountered excellent Vivian sands with over 840 meters of net pay. Available production capacity is essential for allowing the Company to ramp up production quickly when additional sales capacity become available.

Full repayment of bonds. On February 15, 2023, the Company made the regularly scheduled payment to bondholders totaling $25 million, plus accrued interest. In addition, on March 24, 2023, PetroTal fulfilled its promise to shareholders and repaid the remaining $55 million of bonds, plus $3 million of accrued interest and prepayment fees, thereby allowing for shareholder return commencement.

Production resumes at over 20,000 bopd from barge travel normalization. Low river levels late in 2022 caused an overweighting of available barges to the field in late December 2022 and early 2023. During January and February 2023, the Company was only able to produce approximately 7,600 bopd and 8,000 bopd, respectively. Late in February 2023, the Company was able to ramp up production and will now produce and sell into an evenly distributed and expanded barge fleet chain for the remainder of the year. Production from March 1, 2023 until March 29, 2023 has averaged approximately 20,500 bopd.

Well 12H on pump and producing at strong rates. During Q1 2023, well 12H was put on pump and has averaged approximately 5,200 bopd since it was put on pump the last week of February, following the field's type curve for horizontal wells. This drilling location has increased the probability for additional drilling locations to the south of well 12H and 13H.

Return of capital focused 2023 budget. On January 16, 2023, PetroTal announced a $125 million fully funded capital program that targets average production between 14,000 and 15,000 bopd in 2023 with possible river level upside allowing 17,000 bopd in the second half 2023. Under base case production guidance, EBITDA is projected to be $220 million using an $84/bbl average 2022 Brent oil price. This generates after-tax free funds flow of $55 million, strengthening total accessible cash in 2023 to $241 million prior to debt service.

TSX-V award winner and TSX graduation. PetroTal was recognized as a top TSX Venture exchange performer for 2022 ranking 4th in share performance and market capitalization size in the energy sector. On February 16, 2023, PetroTal graduated to the TSX under the same trading symbol "TAL".

2.5% community social trust approved into Supreme Decree. On March 9, 2023, the Company announced the publication of the Supreme Decree signed by Peru's President authorizing Perupetro to execute the amendment incorporating the 2.5% Community Social Trust Fund into the Block 95 License Contract. Bylaw approvals for the trust are expected to occur by the end of April 2023, at which time the amendment to the License Contract shall be executed.

Barging fleet expanded. The Company has expanded its gross contracted barging fleet by over 25% to 1.5 million barrels from the previous capacity of 1.2 million. By increasing the fleet export capacity, the Company will be better able to mitigate situations where barge carrying capacity is limited and/or slow moving. The Company anticipates selling approximately 640,000 barrels of oil in March 2023, mostly through the Brazil export route, and expects deliveries of 550,000 barrels in April 2023, under normalized river conditions. March would then be the first month in PetroTal's history that 600,000 barrels of oil are sold via Brazil, which was an initial goal when the first 140,000 barrel Brazilian export was completed in December 2020. Now the Company is committed to replicating this on a consistent basis, even during the dry season.

New working capital credit line secured. PetroTal has successfully secured a revolving working capital line of credit for approximately $20 million with a Peruvian bank. The working capital line will allow the Company to better manage a stable return of capital program, in conjunction with ensuring cash liquidity. The revolving working capital line can be drawn and repaid at any time.

Return of Capital Update

PetroTal is now long-term debt free and is excited to announce Board approval of a normal course issuer bid ("NCIB") share buyback program. Subject to approval by the Toronto Stock Exchange, the NCIB will allow the Company to purchase up to 10% of PetroTal's public float, over a period of twelve months, commencing in Q2 2023. Under the NCIB, common shares may be repurchased on the open market through the facilities of both the TSX and AIM exchanges, in accordance with TSX and AIM regulations.

In addition, PetroTal is pleased to reinstate a US$0.015 per share quarterly eligible dividend[(1)] with expected record and payment dates in June 2023. On an annualized basis, this represents US$0.06/share and an approximate yield of 13.9% based on a trading price of US$0.45/share. This quarterly cash dividend will be designated as an "eligible dividend" for Canadian income tax purposes.

(1) See reader advisories.

Updated Corporate Presentation and Investor Webcast

PetroTal will host a virtual investor webcast meeting on March 30, 2023, following the release of these 2022 results. See the link below to join the webcast beginning at 9am Central Time and 3pm London time. The Company has also provided an updated corporate presentation with the 2022 results, on its website.

https://stream.brrmedia.co.uk/broadcast/63ff1852d684866e54345b62

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 Bretana 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 Bretana 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.sedar.com, or below:

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READER ADVISORIES

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: PetroTal's business strategy, objectives, strength and focus; drilling, completions, workovers and other activities and the anticipated costs and results of such activities; PetroTal's anticipated capital program and operational results for 2023 including, but not limited to, estimated or anticipated production levels, capital expenditures and drilling plans; plans to deliver strong operational performance and to generate free funds flow and growth; capital requirements; the ability of the Company to achieve drilling success consistent with management's expectations; anticipated future production and revenue; drilling plans including the timing of *drilling, commissioning, and startup and the impact of delays thereon; oil production levels; and the Company's return of capital strategy including regular dividends and share buybacks under an NCIB. All statements other than statements of historical fact may be forward-looking statements. In addition, statements relating to expected production, reserves, recovery, replacement, 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. 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" and similar expressions. More particularly, this press release contains statements concerning the future declaration and payment of dividends and the timing and amount thereof. Future dividend payments, if any, and the level thereof, is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, free funds flow financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of PetroTal to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness. 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 of the Ministry of Energy to effectively achieve its 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. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These 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), 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 and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; changes in the financial landscape both domestically and abroad, including volatility in the stock market and financial system; and wars (including Russia's war in Ukraine). In addition, the Company cautions that current global uncertainty with respect to the spread and evolution of the COVID-19 virus and its effect on the broader global economy may have a significant negative effect on the Company. While the precise impact of the COVID-19 virus on the Company remains unknown, rapid spread of the COVID-19 virus may continue to have a material adverse effect on global economic activity, and may continue to result in volatility and disruption to global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, increased operating and capital costs due to inflationary pressures, business, financial conditions, results of operations and other factors relevant to the Company. Please refer to the risk factors identified in the Company's AIF and MD&A which are available on SEDAR at www.sedar.com. 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 NI 51-101. All references to Brent indicate Intercontinental Exchange ("ICE") Brent. Recovery factor percentages include historical production.

RESERVES DISCLOSURE: All reserves values, future net revenue and ancillary information contained in this press release are derived from the NSAI Report unless otherwise noted. Estimates of reserves and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves and future net revenue for all properties, due to the effect of aggregation. There is no assurance that the forecast price and cost assumptions applied by NSAI in evaluating PetroTal's reserves will be attained and variances could be material. It should not be assumed *that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. The recovery and reserve estimates of PetroTal's oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil reserves may be greater than or less than the estimates provided herein. There are numerous uncertainties inherent in estimating quantities of crude oil, reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Proved developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty. Possible reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned. Certain terms used in this press release but not defined are defined in NI 51-101, CSA Staff Notice 51-324 - Revised Glossary to NI 51-101, Revised Glossary to NI 51-101, Standards of Disclosure for Oil and Gas Activities ("CSA Staff Notice 51-324") and/or the COGEH and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 and the COGEH, as the case may be.*

DRILLING LOCATIONS: This press release discloses drilling inventory in three categories: (a) proved locations; (b) probable locations; and (c) possible locations, all of which are derived from the NSAI Report and account for drilling locations that have associated proved, probable and/or possible reserves, as applicable. There is no certainty that PetroTal will drill all booked drilling locations and if drilled there is no certainty that such locations will result in additional oil reserves or production. The drilling locations considered for future development will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the possible drilling locations have been de-risked by drilling existing wells in relative close proximity to such drilling locations, other possible drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil reserves or production.

SHORT-TERM PRODUCTION RATES: References in this press release to the peak rates and other short term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rate 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 for PetroTal. The Company cautions that such results should be considered to be preliminary.

SPECIFIED FINANCIAL MEASURES: This press release includes various specified financial measures, including non-GAAP financial measures, non-GAAP financial ratios and capital management measures as further described herein. These measures do not have a standardized meaning prescribed by generally accepted accounting principles ("GAAP") and, therefore, may not be comparable with the calculation of similar measures 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. "Netback" (non-GAAP financial ratio) equals total petroleum sales less quality discount, lifting costs, transportation costs and royalty payments calculated on a bbl basis. The Company considers netbacks to be a key measure as they demonstrate Company's profitability relative to current commodity prices. "Funds flow provided by operations" (non-GAAP financial measure) includes all cash generated from operating activities and is calculated before changes in non-cash working capital. "Adjusted EBITDA" (non-GAAP financial measure) is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization and adjusted for G&A impacts and certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses, including derivative true-up settlements. PetroTal utilizes adjusted EBITDA as a measure of operational performance and cash flow generating capability. Adjusted EBITDA impacts the level and extent of funding for capital projects investments. Reference to EBITDA is calculated as net operating income less G&A. "Free funds flow" (non-GAAP financial measure) is calculated as net operating income less G&A less exploration and development capital expenditures less realized derivative gains/losses and is calculated prior to all debt service, taxes, lease payments, hedge costs, factoring, and lease payments. Management uses free cash flow to determine the amount of funds available to the Company for future capital allocation decisions. Please refer to the MD&A for additional information relating to specified financial measures.

OIL AND GAS MEASURES: This press release contains metrics commonly used in the oil and natural gas industry which have been prepared by management, such as "OOIP", "development capital", "F&D costs", "net asset value" and "reserves life index". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. "OOIP" is equivalent to total petroleum initially-in-place ("TPIIP"). TPIIP, as defined in the COGEH, is that quantity of petroleum that is estimated to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the TPIIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the TPIIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of TPIIP will never be recovered. "Development capital" means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development. Development capital excludes capitalized administration costs. "Finding and development costs" or "F&D costs" are calculated as the sum of field capital plus the change in future development costs for the period divided by the change in reserves that are characterized as development for the period. Finding and development costs take into account reserves revisions during the year on a per bbl basis. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. "Net asset value" is based on present value of future net revenues discounted at 10% before tax on reserves, net of estimated net debt at year-end divided by the basic shares outstanding at year-end. "Reserve life index" is calculated as total Company interest reserves divided by annual production. These terms have been calculated by management and do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare PetroTal's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

ELIGIBLE DIVIDEND: An eligible dividend is one which is characterized as such by the dividend-paying corporation for Canadian residents. The primary benefit of an eligible dividend is that it benefits from an enhanced gross-up and credit regime at the shareholder level (i.e., the shareholder pays less tax on eligible dividends than non-eligible dividends). This is meant to compensate for the higher general corporate tax rate paid by non-CCPC's on their income and generally preserve integration of Canada's tax rates. As an example, for federal income tax purposes the gross-up rate for eligible dividends is 38% (as compared to 15% for non-eligible dividends) such that the amount of the dividend is multiplied by 1.38 to determine the taxable income to the shareholder. The dividend tax credit for eligible dividends is additionally increased to 6/11 (or 15.02%), as compared to 9/13 (9%) for non-eligible dividends, to offset the greater income inclusion to the taxpayer. Each province provides similar relief on the tax they would otherwise levy on the dividends, although the effective gross-up and credit differs by province.

FOFI DISCLOSURE: This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about NPV-10, future development and abandonment costs, prospective results of operations, production and production capacity, free funds flow, revenue, margins, NOI, shareholder returns 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.

Neither the TSX Exchange nor its Regulation Services Provider (as that term is defined in the policies of the TSX Exchange) accepts responsibility for the adequacy or accuracy of this press release.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2022 and 2021

TSX:TAL
AIM: PTAL
OTCQX: PTALF

PetroTal

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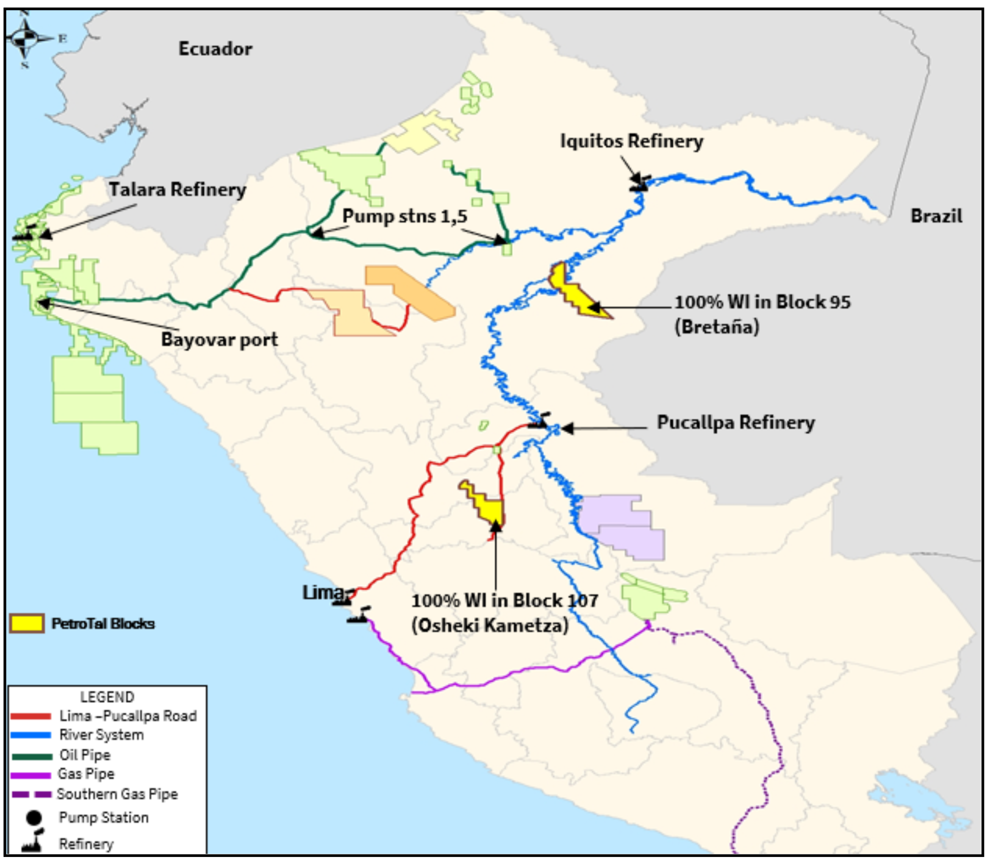
MANAGEMENT'S DISCUSSION AND ANALYSIS

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, 2022 and 2021, is dated March 29, 2023, and should be read in conjunction with the Company's audited Consolidated Financial Statements (the "Financial Statements") for the twelve months ended December 31, 2022 and 2021 and the Company's Annual Information Form (the "AIF") for the year ended December 31, 2022. The audited Financial Statements were prepared by management in accordance with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board, which are also 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. is a publicly-traded (TSX: TAL, AIM: PTAL, and OTCQX: PTALF) international oil and gas company incorporated and domiciled in Canada, with management based in Houston, Texas and Lima, Peru. Through its two subsidiaries in Peru, the Company is currently engaged in the ongoing development of hydrocarbons in Block 95 with a focus on the development of, and production from the Bretana oil field. In addition to further leads in Block 95, the Company has significant exploration prospects and leads in Block 107.



The Bretana oil field is located in the Maranon Basin of northern Peru. To date, this basin has produced more than one billion barrels of oil. Approximately 70% of the oil in the Maranon Basin has been produced from the Vivian formation and approximately 30% from the Chonta formation. The Vivian formation is known as a quality oil reservoir with high permeabilities and strong aquifer support. Generally, this type of reservoir achieves the highest oil recoveries. The Chonta formation is immediately below the Vivian and typically produces medium to light oil; the Company is focused on the Vivian formation. The Company has a 100% working interest in the Bretana oil field.

2. OVERVIEW AND SELECTED INFORMATION

The following table summarizes key financial and operating highlights associated with the Company's performance for the periods ended December 31, 2022, September 30, 2022, June 30, 2022, March 31, 2022 and December 31, 2021.

RESULTS AT A GLANCE

	Twelve Months Ended		Three Months Ended			
	December 31, 2022	December 31, 2021	December 31, 2022	September 30, 2022	June 30, 2022	March 31, 2022
Financial						
Oil revenue	$359,106	$159,189	$63,755	$84,164	$118,435	$92,752
Royalties [(1)]	($31,991)	($8,962)	($5,824)	($11,689)	($8,104)	($6,373)
Net operating income [(2)]	$273,539	$104,960	$48,422	$62,333	$98,589	$64,194
Commodity price derivatives (gain) loss	($8,231)	($13,036)	($13,373)	$32,686	($6,533)	($21,014)
Net income	$188,527	$63,972	$37,176	$2,594	$84,249	$64,511
Basic earnings per share ($/share)	0.22	0.08	0.04	0.00	0.10	0.07
Capital expenditures	$94,203	$82,191	$32,025	$20,625	$24,024	$17,529
Operating						
Average production (bopd)	12,200	8,966	10,374	12,229	14,467	11,746
Average sales (bopd)	13,168	8,449	10,420	12,186	14,616	15,518
Average Brent ICE price ($/bbl)	98.92	70.82	88.61	97.89	111.80	97.49
Contracted sales price ($/bbl)	96.67	68.22	88.22	97.21	111.39	88.02
Netback ($/bbl) [(2)]	56.90	34.03	50.51	55.58	74.13	45.97
Funds flow provided by operations [(3)]	$172,020	$77,456	$59,383	$46,205	$60,688	$5,743
Balance Sheet						
Cash and restricted cash	$119,969	$74,459	$119,969	$93,018	$77,017	$52,886
Working capital	$139,771	$47,319	$139,771	$136,338	$141,971	$54,226
Total assets	$602,880	$398,288	$602,880	$549,838	$535,202	$455,370
Current liabilities	$123,362	$84,767	$123,362	$110,160	$92,988	$100,904
Equity	$399,331	$204,257	$399,331	$361,367	$357,732	$270,855

(1) Royalties in Q3 2022 include the value since January 1, 2022 inception for the 2.5% social trust initiative. Royalties incurred thereafter were recorded in the period they were incurred.
(2) Net operating income ("NOI") and Netback represent revenues less royalties, operating expenses and direct transportation.
(3) Funds flow provided by operations does not have standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures for other entities. See "Non-GAAP Measures" section.

3. 2022 HIGHLIGHTS

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

Three months ended December 31, 2022 ("Q4") Highlights

- Oil production averaged 10,374 barrels of oil per day ("bopd"), a decrease of 15% from 12,229 bopd in Q3 2022, and in line with 10,147 bopd in Q4 2021. At December 31, 2022, the Company has 14 producing wells and 2 water disposal wells;
- Q4 2022 was an unseasonally dry quarter in the Bretana area, leading to low river levels that curtailed oil exports through Brazil with barges having reduced capacity to ensure safe operations;
- On October 13, 2022, the 13H oil well reached total depth and successfully tested at approximately 8,000 bopd over its first week of production;
- On October 16, 2022, the Company commenced drilling the 12H oil well and successfully completed it on December 16, 2022, with production averaging 2,900 bopd over the first 10 days;
- The Company commenced drilling the 4WD water disposal well ("4WD") on December 21, 2022, which was subsequently completed on January 29, 2023;
- On December 22, 2022, Perupetro's board approved the social trust addendum, authorizing the Block 95 license contract to be amended for inclusion of the 2.5% community social trust;
- PetroTal reached agreement with Petroperu for repayment of $64 million owing to the Company for oil sales from mid-2022; and,
- Oil sales allocations were 84% as export through Brazil and 16% to the Iquitos refinery.

2022 Operational Highlights

- Oil production of 4.5 million of barrels of oil ("mmbbl") in 2022, representing an average of 12,200 bopd, an increase of 36% from 8,966 bopd realized in 2021;
- Annual independent reserve assessment, as prepared by Netherland Sewell and Associates, Inc. ("NSAI") shows increases in all reserve categories:

  - Proved ("1P") reserves increased by 21% to 45.5 mmbbl. Net present value discounted at 10% ("NPV-10") after tax is $0.8 billion ($17.25/bbl, CAD $23.56/bbl);
  - Proved plus Probable ("2P") reserves increased by 24% to 96.8 mmbbl. NPV-10 after tax is $1.5 billion ($15.60/bbl, CAD $21.31/bbl); and,
  - Proved plus Probable and Possible ("3P") reserves increased by 14% to 168.4 mmbbl. NPV-10 after tax is $2.5 billion ($14.67/bbl, CAD $20.03/bbl).

- Original oil in place ("OOIP") increases of 33%, 14% and 2% to 329, 445 and 632 mmbbl, respectively for the 1P, 2P and 3P cases; and,
- Oil sales allocations were 71% as export through Brazil, 15% through the North Peruvian Oil Pipeline ("ONP"), and 14% sales to Iquitos refinery.

2022 Financial Highlights

- The Company generated revenue of $359.1 million (4.8 mmbbl sold, $74.71/bbl) compared to $159.2 million (3.1 mmbbl sold, $51.62/bbl) in 2021;
- Royalties paid to the Peruvian government were $25.7 million ($5.35/bbl, 7.1%) compared to $9.0 million ($2.91/bbl, 5.6%) in 2021. Considering positive developments with the community groups towards development of the previously announced 2.5% community social trust fund, the Company is including a $6.3 million provision retroactive to January 1, 2022;
- Generated funds flow from operations of $172.0 million compared to $77.5 million in 2021;
- Net operating income was $273.5 million ($56.90/bbl) compared to $105 million ($34.03/bbl) in 2021; and,
- On December 31, 2022, the Company had cash and restricted cash of $120 million, compared to $74.5 million at December 31, 2021.

December 31, 2022 Subsequent Events

- On January 16, 2023, the Company announced its intention to provide shareholder returns, subject to the bond payout and corporate liquidity, through a combination of share buybacks and a dividend policy;
- The 4WD water disposal well was completed on January 29, 2023, thereby providing additional water disposal capacity to accommodate increased oil production;
- On February 8, 2023, the Company commenced drilling the 14H oil well, with an estimated cost of $15.3 million, and expected to be completed in April 2023;
- On March 24, 2023, the Company fully repaid the remaining $55 million of corporate bonds, in addition to the $25 million regularly scheduled payment on February 16, 2023; and,
- The Company announced publication of the Supreme Decree signed by Peru's President authorizing Perupetro to execute the amendment incorporating the 2.5% community social trust fund into the Block 95 license contract. The social trust now requires its bylaws to be approved by the working table participants which is estimated to occur in April 2023.

4. OUTLOOK AND GROWTH STRATEGY

Strategy Outlook

The capital program prioritizes management's strategy to maintain a strong balance sheet during the period of oil price volatility, optimizing drilling activity to fit within cash flow. The Company activity will focus on managing existing production and drilling new wells during 2023. Base maintenance capital would require capital expenditures and additional activities included in the capital program outlined as follows:

- Completion of production facilities and infrastructure activities which include optimization of existing facilities, wells and some improvements aimed at lowering operating costs;
- Drilling new wells focused on continuing development in the core area of Bretana oilfield; and,

- Continued investment in environmental remediation and social initiatives as part of a sustained long-term effort to improve the physical environment, and to provide training programs and other community initiatives for the residents near the Company's operations.

The 2023 capital budget is based on an estimated average annual Brent oil price forecast of $85/bbl. Additionally, the Company will continue with an appropriate oil price hedging strategy for the future.

Growth Strategy

PetroTal's strategy is focused on petroleum assets that have long-life reserves with production growth potential. Employing its knowledge base and technical expertise, the Company is working to optimize its existing assets primarily through drilling new oil wells to create long-term value for shareholders. This will be accomplished through the attainment of its main objectives: increasing production, reserves, funds generated from operations, and net asset value.

PetroTal's strategic priorities are to:
- Increase reserves and production;
- Maintain a strong balance sheet by controlling and managing capital expenditures;
- Control costs through efficient management of operations;
- Pursue new and proven technology applications to improve operations and assist exploration endeavors;
- Expand infrastructure (pipelines, storage, treating capacity) to increase production capacity in a cost-effective manner; and,
- Explore undeveloped acreage to identify and create development opportunities.

Throughout the period, PetroTal focused on achieving its priorities and implementing its capital programs in Peru. The Company will fund its capital development program using funds generated from operations and existing cash. Strategic allocation of the work program and budget is designated to provide additional recoverable reserves at the Peruvian oilfields and achieve production growth.

Environmental and Social Governance ("ESG") Strategy

PetroTal believes in creating long-term value for our shareholders, employees, suppliers, communities, customers, government, as well as ensuring economic value, safety for people and the environment, and a better future for all. Therefore, our sustainability strategy to year 2030 rests on our shoulders. PetroTal's ESG vision is: "To create value and generate more opportunities for the benefit of all". The steps to measure our success are:

- Develop measurable goals for 2025 and 2030 that will be built and reviewed with the participation of each department throughout the Company;
- Initiatives will be continually updated to achieve our goals;
- The Sustainable Development Goals ("SDGs") will be included, to which PetroTal contributes through its Sustainability Plan to 2030;
- We are committed to reducing our carbon and water footprints, which means reducing emissions, waste, preventing oil spills as much as possible, efficiently managing our use of water, focusing on the protection and conservation of biodiversity, managing our impact positively, innovating where possible and doing all of the above safely;
- We are implementing an effective due diligence process to prevent possible human rights violations;
- To materialize the aforementioned initiatives, we develop and promote talent in PetroTal, the community and within our suppliers; and,
- We maintain a constant and respectful dialogue with our stakeholders to inform and prevent conflicts.

Exploratory Block 107 – Osheki-Kametza

PetroTal has a 100% working interest in this 623,280-acre block, of which the Osheki prospect has a best estimate of 278.4 million barrels of prospective recoverable oil resources according to NSAI. This estimate is based on a recovery factor of 28.6% of the estimated 970.7 million barrels of best estimate prospective OOIP. Resource estimates are based on maps generated from modern seismic acquired in 2007 and 2014 and de-risked with a new 3D geologic model supporting Cretaceous age reservoirs with high quality Permian source rocks. Additional seismic acquisition will be required to redefine the structural configuration. Block 107 has three additional leads that, inclusive of the Osheki-Kametza prospect, could contain a total of 662 million barrels of recoverable resource in the best estimate case. The Company continues to work on the necessary drilling permit for the Osheki-Kametza prospect. On January 6, 2023, Perupetro extended the Company's Block 107 exploratory license to May 2026.

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5. SELECTED FINANCIAL INFORMATION

5.1 FINANCIAL SUMMARY

		2022		Q4-2022		Q3-2022		Q2-2022		Q1-2022	
($ thousands)		$/bbl		$/bbl		$/bbl		$/bbl		$/bbl	
PRODUCTION:	Average Production (bopd)		12,200		10,374		12,229		14,467		11,746
SALES:	Average sales (bopd)		13,168		10,420		12,186		14,616		15,518
	Total sales (bbls)		4,806,431		958,624		1,121,132		1,330,025		1,396,648
	Average Brent ICE price	$98.92		$88.61		$97.89		$111.80		$97.49	
	Contracted sales price, gross	$96.67		$88.22		$97.21		$111.39		$88.02	
LESS:	Tariffs, fees and differentials	($21.96)		($21.71)		($22.14)		($22.35)		($21.61)	
	Realized sales price, net	$74.71		$66.51		$75.07		$89.04		$66.41	
REVENUES:	Oil revenue (1)	$74.71	$359,106	$66.51	$63,755	$75.07	$84,164	$89.04	$118,435	$66.41	$92,752
LESS:	Royalties (2)	$6.66	$31,991	$6.08	$5,824	$10.43	$11,689	$6.09	$8,104	$4.56	$6,373
	Operating expense	$6.86	$32,954	$7.42	$7,115	$6.62	$7,423	$6.28	$8,355	$7.20	$10,061
	Direct Transportation:										
	Diluent	$1.96	$9,440	$1.33	$1,274	$1.23	$1,374	$1.45	$1,931	$3.48	$4,862
	Barging	$1.34	$6,431	$0.86	$824	$1.05	$1,172	$0.71	$943	$2.50	$3,493
	Diesel	$0.23	$1,083	$0.15	$144	$0.10	$110	$0.05	$71	$0.54	$758
	Storage	$0.76	$3,668	$0.16	$152	$0.06	$63	$0.33	$442	$2.16	$3,011
	Total Transportation	$4.29	$20,622	$2.50	$2,394	$2.44	$2,719	$2.54	$3,387	$8.68	$12,124
NET OPERATING INCOME		$56.90	$273,539	$50.51	$48,422	$55.58	$62,333	$74.13	$98,589	$45.97	$64,194
	Netback as % of Revenue		*76.2%*		*76.0%*		*74.1%*		*83.2%*		*69.2%*
General and administrative expense		$4.14	$19,891	$5.57	$5,339	$4.18	$4,689	$3.87	$5,143	$3.38	$4,718
Commodity price derivative loss (gain)		($1.71)	($8,231)	($13.95)	($13,373)	$29.15	$32,686	($4.91)	($6,533)	($15.05)	($21,014)
Financial expense		$4.20	$20,169	$2.49	$2,387	$5.17	$5,792	$4.60	$6,113	$4.21	$5,878
Income tax expense (recovery)		$3.62	$17,390	$9.36	$8,975	$7.49	$8,392	$0.04	$53	($0.02)	($29)
Depletion, depreciation and amortization		$6.98	$33,568	$7.42	$7,116	$7.06	$7,920	$6.90	$9,179	$6.70	$9,353
Other expenses		$0.20	$978	$1.02	$978	—	—	—	—	—	—
Foreign exchange loss (gain)		$0.26	$1,247	($0.18)	($176)	$0.23	$260	$0.29	$385	$0.56	$777
NET INCOME			$188,527		$37,176		$2,594		$84,249		$64,511
FUNDS FLOW PROVIDED BY OPERATIONS			$172,020		$59,383		$46,205		$60,688		$5,743

(1) Tariff and marketing fees are expenses usually recorded by reducing revenues in the financial statements.

(2) Royalties in Q3 2022 include the value since January 1, 2022 inception for the 2.5% community social trust initiative. Royalties incurred thereafter were recorded in the period they were incurred.

		2021		Q4-2021		Q3-2021		Q2-2021		Q1-2021	
($ thousands)		$/bbl		$/bbl		$/bbl		$/bbl		$/bbl	
PRODUCTION:	Average Production (bopd)		8,966		10,147		9,508		8,839		7,331
SALES:	Average sales (bopd)		8,449		7,242		9,142		8,842		8,578
	Total sales (bbls)		3,084,033		666,301		841,101		804,620		772,011
	Average Brent ICE price	$70.82		$79.79		$73.21		$69.01		$61.06	
	Contracted sales price, gross	$68.22		$77.46		$71.06		$66.55		$58.88	
LESS:	Tariffs, fees and differentials	($16.60)		($18.56)		($17.82)		($13.34)		($16.97)	
	Realized sales price, net	$51.62		$58.90		$53.24		$53.20		$41.91	
REVENUES:	Oil revenue [1]	$51.62	$159,189	$58.90	$39,243	$53.24	$44,781	$53.20	$42,809	$41.91	$32,356
LESS:	Royalties	$2.91	$8,962	$3.46	$2,304	$3.10	$2,604	$2.87	$2,306	$2.26	$1,748
	Operating expense	$6.99	$21,544	$7.60	$5,063	$6.47	$5,442	$6.84	$5,506	$7.17	$5,533
	Direct Transportation:										
	Diluent	$3.91	$12,069	$4.21	$2,805	$4.17	$3,504	$3.61	$2,902	$3.70	$2,858
	Barging	$2.01	$6,214	$1.46	$975	$2.01	$1,693	$2.30	$1,851	$2.20	$1,695
	Diesel	$0.61	$1,874	$0.69	$458	$0.62	$521	$0.54	$438	$0.59	$457
	Storage	$1.16	$3,566	$2.87	$1,911	$1.70	$1,430	$0.16	$129	$0.12	$96
	Total Transportation	$7.69	$23,723	$9.23	$6,149	$8.50	$7,148	$6.61	$5,320	$6.61	$5,106
NET OPERATING INCOME		$34.03	$104,960	$38.61	$25,727	$35.17	$29,587	$36.88	$29,677	$25.87	$19,969
	Netback as % of Revenue		*65.9%*		*65.6%*		*66.1%*		*69.3%*		*61.7%*
General and administrative expense		$4.63	$14,282	$5.95	$3,965	$4.11	$3,459	$4.01	$3,227	$4.70	$3,631
Commodity price derivative loss (gain)		($4.23)	($13,036)	$8.44	$5,622	($0.35)	($293)	$5.15	$4,147	($29.16)	($22,512)
Financial expense		$5.78	$17,838	$6.78	$4,519	$6.59	$5,542	$6.26	$5,039	$3.55	$2,738
Income tax expense (recovery)		$—	($4)	$0.02	$10	$0.02	$20	($0.28)	($224)	$0.25	$190
Depletion, depreciation and amortization		$7.01	$21,630	$7.14	$4,758	$6.89	$5,797	$7.45	$5,994	$6.58	$5,081
Foreign exchange loss		$0.09	$278	$0.01	$9	$0.11	$92	$0.15	$121	$0.07	$56
NET INCOME			$63,972		$6,844		$14,970		$11,373		$30,785
FUNDS FLOW PROVIDED BY OPERATIONS			$77,456		$34,714		$18,648		$19,627		$4,467

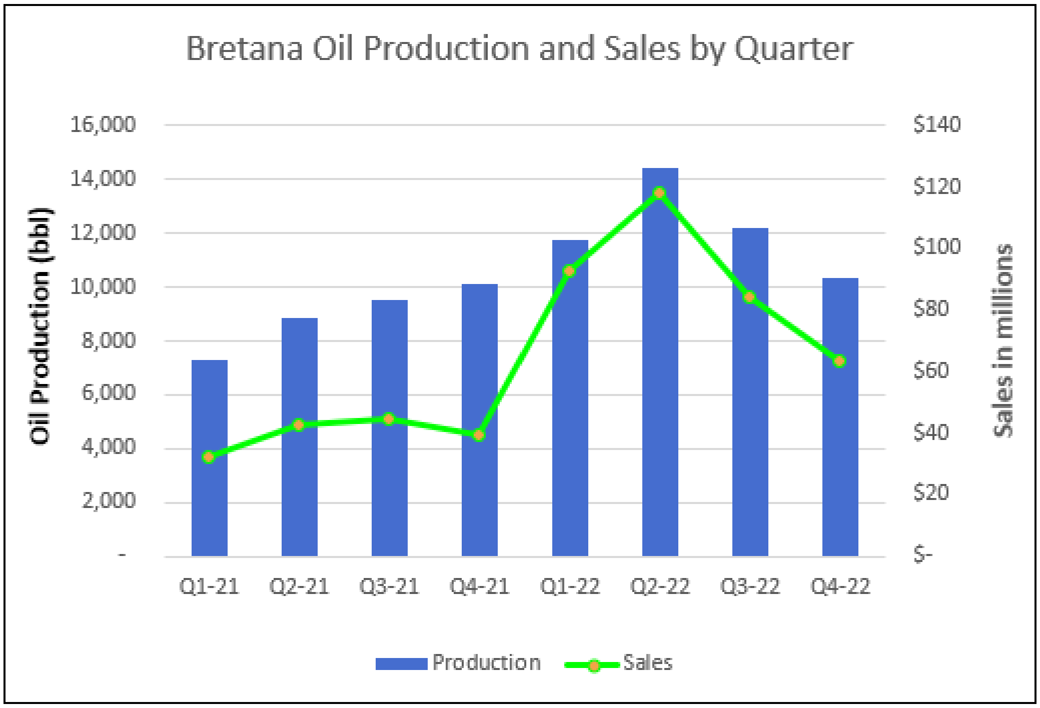
(1) Tariff and marketing fees are expenses usually recorded by reducing revenues in the financial statements.

EARNINGS STATEMENT INFORMATION

Revenue

Oil sales in 2022 were 4,806,431 barrels (13,168 bopd), compared to 3,084,033 barrels (8,449 bopd) in 2021. Sales were 958,624 barrels (10,420 bopd) in Q4 2022 compared to 666,301 (7,242 bopd) in Q4 2021. During 2022, social conflicts and low river levels curtailed oil exports through Brazil with barges having lower volumes.

The Company sells oil at three sales points: the local Iquitos refinery, exports through Brazil, and the ONP pipeline. In 2022, 71% of oil sales were through the Brazil export route, 15% through the ONP pipeline and 14% to the Iquitos refinery. Sales to the Iquitos refinery are priced at the prevailing Brent oil price less a quality differential discount and barge transportation charges. Oil sales exported through Brazil are on an FOB Bretana basis, at the forecasted Brent oil price in three months, less a fixed amount to cover all transportation and sales costs, including the quality differential. Sales to Petroperu at the Saramuro pump station for transportation through the ONP and onward to the Bayovar port, are priced based on the forecasted Brent oil price in eight months, less a quality differential, and is 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 by Petroperu, whether higher or lower than the original forecasted price. Using the future price and the sales basis minimizes the impact of oil price fluctuations.



Royalties increased to $32 million ($6.66/bbl) in 2022 from $9 million ($2.91/bbl) in 2021 and in Q4 2022 increased to $5.8 million ($6.08/bbl) from $2.3 million ($3.46/bbl) in Q4 2021. Royalties in 2022 now include the 2.5% community social trust initiative. Royalties for the Bretana oilfield are calculated on production, less transportation costs, starting at 5% based on production of 5,000 bopd or less and 20% when production reaches 100,000 bopd or more, increasing on a straight-line basis. Royalty determination in Peru is negotiated on an individual block basis, based either on production scales or on economic results.

Operating expenses in 2022 were $33 million ($4.29/bbl), as compared to $21.5 million ($6.99/bbl) in 2021 and in Q4 2022 were $7.1 million ($7.42/bbl) versus $5.1 million ($7.60/bbl) Q4 2021. As production and oil field operations increase, the fixed operating cost allocations become more economic.

Direct Transportation expenses in 2022 totaled $20.6 million ($4.29/bbl), representing barging and diluent blending costs, as compared to $23.7 million ($7.69/bbl) in 2021 and in Q4 2022 totaled $2.4 million ($2.50/bbl) versus $6.1 million ($9.23/bbl) in Q4 2021. Diluent costs decreased in 2022 as a result of no blending requirements for oil exports through Brazil. Direct transportation costs are impacted by oil inventory fluctuation valuations.

	Q4 2022	2022
Diluent	1,274	9,440
Barging	824	6,431
Diesel	144	1,083
Storage	152	3,668
Total Direct Transportation	2,394	20,622

General and administrative ("G&A") expenses in 2022 were $19.9 million ($4.14/bbl), as compared to $14.3 million ($4.63/bbl) in 2021 and $5.3 million ($5.57/bbl) in Q4 2022 compared to $4.0 million ($5.95/bbl) in Q4 2021. As production increases, per barrel G&A costs will decrease. The 2022 increase in G&A was mainly due to an increase in non-cash equity-based compensation related to the Company's Performance Share Unit (PSU) and Deferred Share Unit (DSU) plans, an increase in salaries and headcount, professional fees and ESG consulting expenses, partially offset by G&A allocations.

	Twelve months ended	
	December 31 2022	December 31 2021
Salaries and benefits	10,994	9,387
Legal, audit and consulting fees	4,830	3,051
Community support	2,372	1,451
Office rent and administrative	2,870	1,678
Share-based compensation	4,089	2,548
G&A allocations	(5,264)	(3,833)
Total	19,891	14,282

Included in G&A are expenditures related to various community project initiatives for Bretana and neighboring communities. PetroTal recognizes the importance of community alignment and support over the areas in which it operates.

The Company allocated $5.3 million of G&A in 2022 to capital and operating projects, compared to $3.8 million in 2021. For the year ended December 31, 2022, non-cash PSU compensation granted to employees was $3 million (2021: $1.7 million).

Depletion, Depreciation and Amortization ("DD&A") for 2022 was $33.6 million ($6.98/bbl) as compared to $21.6 million ($7.01/bbl) in 2021 and in Q4 2022 totaled $7.1 million ($7.42/bbl) versus $4.8 million ($7.14/bbl) in Q4 2021. DD&A is determined using the annual reserve report information prepared by NSAI at December 31, 2022. DD&A is calculated based on capital invested, future capital, production and 2P reserves.

Commodity price derivative gain of $8.2 million in 2022 is the net fair value change of outstanding embedded derivatives, compared to a $13.0 million derivative gain in 2021. The oil sales agreement with Petroperu for sales into the ONP are subject to oil price variations when sold by Petroperu upon arrival at the Bayovar port.

Foreign exchange loss in 2022 was $1.2 million compared to $278 thousand in 2021, and a $176 thousand gain in Q4 2022 as compared to a $9 thousand loss in Q4 2021, due to fluctuations in relative currency positions and transactions.

Income tax expense of $17.4 million was recorded in 2022 compared to a $4 thousand income tax recovery in 2021.

Financial expense was $20.2 million in 2022, mainly related to bond interest, factoring expense, and accretion of decommissioning obligation expense, as compared to $17.8 million in 2021. The Company's financial expense was $2.3 million higher in 2022 compared to 2021, mainly due to the financial revaluation of the Ferrenergy lease in Q2 2022.

Other expenses of $0.9 million is related to erosion remediation activities expensed in 2022.

5.2 BALANCE SHEET INFORMATION

BALANCE SHEET - SUMMARIZED

	December 31, 2022	September 30, 2022	June 30, 2022	March 31, 2022	December 31, 2021
$ (thousands)					
Current Assets					
Cash and restricted cash	$113,969	$87,018	$71,017	$46,886	$68,459
VAT receivable	$10,555	$5,256	$3,628	$0	$1,115
Trade and other receivables	$107,275	$121,495	$89,430	$55,788	$2,639
Inventory	$13,773	$11,938	$12,107	$12,913	$22,332
Prepaid expenses	$5,475	$4,294	$3,187	$1,597	$818
Derivative assets	$12,086	$16,497	$55,590	$37,946	$36,723
Total Current Assets	$263,133	$246,498	$234,959	$155,130	$132,086
Restricted cash	$6,000	$6,000	$6,000	$6,000	$6,000
VAT receivables and taxes	$3,032	$2,439	$2,504	$2,505	$2,321
PPE and E&E, net	$319,252	$294,044	$282,483	$265,457	$257,881
Derivative assets	$11,463	$857	$9,256	$26,278	$0
Total Non-current Assets	$339,747	$303,340	$300,243	$300,240	$266,202
Total Assets	$602,880	$549,838	$535,202	$455,370	$398,288
Current Liabilities					
Trade and other payables	$67,195	$50,609	$48,701	$42,556	$55,015
Lease liabilities	$2,567	$2,258	$2,322	$3,580	$3,849
Short-term debt	$53,600	$51,200	$28,600	$46,500	$24,500
VAT payable	$0	$0	$0	$2,173	$0
Short-term derivative liabilities	$0	$2,992	$8,048	$5,459	$0
Decommissioning liabilities	$0	$3,101	$5,317	$636	$1,403
Total Current Liabilities	$123,362	$110,160	$92,988	$100,904	$84,767
Leases and other long-term	$18,384	$19,109	$19,040	$14,692	$14,826
Deferred income tax liabilities	$17,386	$8,369	$18	$32	$40
Long-term debt	$27,845	$27,067	$51,312	$50,618	$73,700
Long-term derivative liabilities	$3,179	$10,858	$0	$0	$0
Decommissioning liabilities	$13,393	$12,908	$14,112	$18,269	$20,698
Total Non-Current Liabilities	$80,187	$78,311	$84,482	$83,611	$109,264
Total Equity	$399,331	$361,367	$357,732	$270,855	$204,257
Total Liabilities and Equity	$602,880	$549,838	$535,202	$455,370	$398,288

Cash and liquidity

At December 31, 2022, the Company held cash and restricted cash of $120 million, a $45.5 million increase from $74.5 million at December 31, 2021. Working capital was $139.8 million at December 31, 2022 as compared to $47.3 million at December 31, 2021. The variance was primarily associated with higher oil production and increased global oil prices, resulting in higher accounts receivable, derivative asset reductions and bond payment amortization.

VAT receivable

	December 31, 2022	December 31, 2021
VAT receivable - current	10,555	1,115
VAT receivable - non-current	1,934	1,692
Total VAT receivables	12,489	2,807

Valued Added Tax ("VAT") in Peru is levied on the purchase of goods and services and is recoverable on contracted oil sales. As a result of capital activity and oil sales during the period, the Company recovered $28.7 million during 2022 and expects to recover $10.6 million in the short-term based on estimated sales.

Trade and other receivables

	December 31, 2022	December 31, 2021
Trade receivables	105,647	441
Other receivables	1,628	2,198
Total trade and other receivables	107,275	2,639

As of December 31, 2022, trade receivables represent revenue related to the sale of oil during the period. The balance is mainly comprised of $74 million due from Petroperu. In addition, $31 million is for export sales through Brazil.

PetroTal reached an agreement with Petroperu for repayment of $64 million owing to the Company, of which $10 million has been collected in 2022. The monthly installments are expected to be collected by August 2023. No credit losses on the Company's trade receivables have been incurred.

Capital expenditures

	Twelve months ended	
	December 31, 2022	December 31, 2021
Drilling program	61,354	57,199
Production facilities	18,415	19,931
Erosion Control	5,517	—
Abandonment	4,917	2,783
Other	4,000	2,278
Total	94,203	82,191

The Company's primary focus is to increase oil production from existing wells, build on the success of drilling new wells and ensure sufficient production facilities. The Company invested $94.2 million in capital programs in 2022, increasing from $82.2 million in 2021.

The Company continues to invest in a variety of community, social and regulatory ("CSR") initiatives. A strong emphasis on ESG is prevalent throughout all areas of our operations.

At December 31, 2022, the Company has $7.3 million of exploration and evaluation assets related to Block 107.

Inventory

	December 31, 2022	December 31, 2021
Oil inventory	2,389	12,222
Materials, parts and supplies	11,384	10,110
Total inventory	13,773	22,332

Oil inventory consists of stored oil barrels, which are valued at the lower of cost or net realizable value. Costs include operating expenses, royalties, transportation, and depletion associated with production. Costs capitalized as inventory will be expensed when the inventory is sold. As of December 31, 2022, the oil inventory balance of $2.4 million consists of 106,621 barrels of oil valued at $22.40/bbl (December 31, 2021: $12.2 million, based on 432,075 barrels of oil at $28.29/bbl). Materials, parts, and supplies, including diluent, are expected to be consumed in the short-term.

	Barrels
Oil inventory at January 1, 2022	432,075
Production	4,453,056
Diluent added	61,993
Internal use (power generation) and other	(34,072)
Sales	(4,806,431)
Oil inventory at December 31, 2022	106,621

Trade and other payables

	December 31, 2022	December 31, 2021
Trade payables	32,177	26,888
Accrued payables and other obligations	35,018	28,127
Total trade and other payables	67,195	55,015

As at December 31, 2022 and December 31, 2021, trade payables and accruals are primarily related to the drilling and completion of wells and construction of production processing facilities.

Commodity Price Derivatives

The derivative asset is classified as a Level 2 fair value measurement. The Petroperu Saramuro agreement, signed with Petroperu during 2021, includes a clause for the purchase price adjustment. The initial sales price is based on the arithmetic average of the ICE Brent 8-month forward price. The realized price is based on the tender price of the oil that is sold at the Bayovar terminal. The purchase price adjustment represents the realized price less the initial sales price, and if negative, the Company will compensate Petroperu the amount, multiplied by the volume sold or arranged by Petroperu. If the purchase price adjustment is positive, the Company will be compensated by Petroperu in a similar manner.

The fair value of the embedded derivative, considering an average future ICE Brent price marker differential, was recorded as a gain on commodity price derivatives at December 31, 2022.

Net derivative asset at January 1, 2022	36,724
Cash settlements	3,585
Cash to be received	(28,171)
Realized gain	17,488
Unrealized gain (loss)	(9,256)
Net derivative asset at December 31, 2022	20,370
Represented as:	
Short-term derivative assets	12,086
Long-term derivative assets	11,463
Short-term derivative liabilities	0
Long-term derivative liabilities	(3,179)

Sales delivery / Executed month	Expected settlement month	Volume mbbls	Price range $/bbl	Hedged range $/bbl	Derivative Asset
Peru Embedded Derivatives (a)					
Jan-21 to Feb-22	Jun-23 to May-25	2,422	55.32 to 85.26	75.42 to 84.76	17,635
Corporate Derivatives Hedging (b)					
Sep-22	Jan-23 to Sep-23	430	—	80.00	2,735
				Net Derivative Asset	**20,370**

a) Embedded derivative related to original Petroperu sales agreement.
b) Corporate hedge program to cover a portion of 2022 oil production.

As of December 31, 2022, 0.9 million barrels have been sold by Petroperu. 2.4 million barrels remain in the pipeline or storage tanks, awaiting final sale by Petroperu and are subject to the same settlement terms as noted above.

Decommissioning obligations

The undiscounted uninflated value of its estimated decommissioning liabilities is $30.2 million. The present value of the obligations was calculated using an average risk-free rate of 6.6% (December 31, 2021: 3.6%) 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 table below sets out the continuity of decommissioning obligations.

Balance at January 1, 2021	21,171
Additions	3,165
Revisions to decommissioning liabilities	106
Expenditures	(2,871)
Accretion	530
Balance at December 31, 2021	22,101
Additions	1,916
Revisions to decommissioning liabilities	(6,604)
Expenditures	(4,917)
Accretion	897
Balance at December 31, 2022	13,393
Represented as:	
Non-current	13,393

Short and long-term debt

On February 2, 2021, PetroTal completed a 3-year senior secured bond with a face value of $100 million issued at a 5% discount for total consideration of $95 million. The bonds bear interest at 12% and interest is due semi-annually with repayments of $25 million in February 2023, $25 million in August 2023 and $50 million in February 2024. On April 1, 2022, the Company elected to repay $20 million to bondholders pursuant to the call option set out in the bond agreement.

US Dollar denominated debt - senior secured bonds		
12% due February 16, 2024	Effective rate 15.7%	80,000
Less: unamortized financing cost		(2,155)
Interest payable		3,600
Balance at December 31, 2022		81,445
Represented as:		
Short-term debt		53,600
Long-term debt		27,845

In accordance with the terms of the bond agreement, the bonds are secured by all assets of the Company, and the Company is required to maintain the following financial ratios:

Covenant	Ratio	Description
a)	Liquidity	Cash amount not less than interest payable for the next 12 months
b)	Equity	Equity to Total Assets minimum rate of 40%
c)	Leverage	Net debt to Adjusted EBITDA not to exceed the ratio of 2:1

The Company met all financial covenants as at December 31, 2022. No distributions to shareholders are permitted until the bonds are relinquished.

Fair Value

The short-term and long-term debt of $81.4 million was comparable to a third-party fair value estimate of $82.0 million for similar issues or current rates. The fair value of the Company's debt on December 31, 2022, was determined by reference to valuation inputs under Level 2 of the fair value hierarchy.

Leases

PetroTal has a seven-year service lease arrangement with a supplier that provides turnkey power generation equipment services. The Company has the option to buy the equipment in year five for $5.5 million. The incremental borrowing rate used to measure the lease liabilities was 7.5% for the dollar denominated lease.

Lease liabilities at January 1, 2021	228
Net additions	16,721
Interest on leases	712
Lease liabilities at December 31, 2021	17,661
Additions	7,263
Revisions	(2,332)
Payments	(3,974)
Interest on leases	1,024
Lease liabilities at December 31, 2022	19,642
Represented as:	
Current liability	2,567
Non-current liability	17,075

As of December 31, 2022, total lease liabilities have the following minimum undiscounted payments per year:

Year	
2023	4,989
2024	5,014
Thereafter	11,139
Total	21,142

Share capital

Authorized share capital consists of an unlimited number of common shares without nominal or par value. The holders of common shares have one vote per share and are entitled to receive dividends as recommended by the Board. During 2022, 25,962,318 warrants were exercised, generating proceeds of $3.5 million.

As of March 29, 2023, PetroTal has the following securities outstanding (in thousands):

Common shares	883,800	94%
Performance share units	19,727	2%
Warrants	38,284	4%
Total	941,812	100%

5.3 NON-GAAP TERMS

This report contains financial terms that are not considered measures under GAAP such as operating netback, operating netback per bbl, revenues and transportation expense adjusted, funds flow provided by operations, funds flow provided by operations per bbl, funds flow netback per bbl, free funds flow and diluted funds flow per share 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.

NON-GAAP FINANCIAL MEASURES

Revenue and transportation expense adjustment

Revenue and transportation expense adjustment are a non-GAAP measure that includes transportation ONP pipeline tariff, marketing fee, barging and diluent expenses. Tariff and marketing fees are expenses usually recorded by reducing revenues in the financial statements.

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 Company's profitability. A reconciliation from cash provided by operating activities to funds flow provided by operations is as follows:

	Three months ended December 31		Twelve months ended December 31	
	2022	2021	2022	2021
Cash flows from operating activities				
Net income	**37,176**	**6,844**	**188,527**	**63,972**
Adjustments for:				
Depletion, depreciation and amortization	7,116	4,758	33,568	21,630
Accretion of decommissioning obligation	238	154	897	530
Equity based compensation expense	997	1,139	3,342	2,361
Financial interest expense	3,522	3,826	17,419	14,132
Deferred income tax expense (recovery)	8,520	10	16,889	(4)
Commodity price unrealized derivatives loss (gain)	(13,375)	11,200	9,256	(13,036)
Funds flow provided by operations before non-cash working capital	**44,194**	**27,931**	**269,898**	**89,585**
Settlement of abandonment liabilities	(2,868)	(2,871)	(4,917)	(2,871)
Changes in non-cash working capital:				
Receivables and restricted cash	8,835	24,318	(114,318)	10,283
Advances and prepaid expenses	171	272	(1,204)	7,122
Inventory	(2,120)	(11,229)	6,240	(12,943)
Trade and other payables	16,015	(3,673)	12,676	(13,415)
Commodity price realized derivatives loss (gain)	(3,492)	—	7,097	—
Cash paid for income taxes	(1,352)	(33)	(3,453)	(305)
Net cash provided by operating activities	**59,383**	**34,715**	**172,019**	**77,456**

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 and is calculated as follows:

	Three months ended December 31		Twelve months ended December 31	
	2022	2021	2022	2021
Cash flows from investing activities				
Exploration and evaluation asset additions	(240)	130	(1,291)	(895)
Property, plant and equipment additions	(31,785)	(26,731)	(92,912)	(81,296)
Capital lease additions	—	(73)	—	(2,019)
Non-cash changes in working capital	563	8,191	(531)	8,016
Net cash used in investing activities	**(31,462)**	**(18,483)**	**(94,734)**	**(76,194)**
Net cash provided by operating and investing activities	**27,921**	**16,231**	**77,285**	**1,262**

CAPITAL MANAGEMENT MEASURES

Adjusted EBITDA

Adjusted EBITDA means earnings before interest, taxes, depreciation and amortization, and derivatives.

	Three months ended December 31		Twelve months ended December 31	
	2022	2021	2022	2021
Net income	37,176	6,844	188,527	63,972
Adjustments to reconcile net income:				
DD&A expenses	7,116	4,758	33,568	21,630
Financial expense	2,387	4,519	20,169	17,838
Income tax expense (recovery)	8,974	10	17,390	(4)
Commodity price derivatives loss (gain)	(13,372)	5,622	(8,231)	(13,036)
EBITDA (non-GAAP)	**42,280**	**21,753**	**251,422**	**90,400**
Realized derivative instruments gain (loss)	9,748	(9,866)	4,647	11,574
Adjusted EBITDA (non-GAAP)	**36,338**	**11,887**	**256,069**	**101,974**
Capital Expenditures	(32,024)	(26,601)	(94,202)	(82,191)
Free funds flow	**4,314**	**(14,714)**	**161,867**	**19,783**

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. For debt covenant purposes, the Company also looks at Adjusted EBITDA.

6. 2022 RESERVE REPORT

Block 95 - Bretana oil field

Oil production commenced in Bretana in June 2018 via a long-term testing program of the single oil producer. In May 2019, the Company received the approval of the Environmental Impact Assessment ("EIA") to fully develop the Bretana field in Block 95. This approval provided PetroTal with the necessary permits to execute its development strategy at Bretana.

The summary below sets forth PetroTal's reserves as at December 31, 2022, as presented by NSAI, a qualified independent reserves evaluator. The figures in the following tables have been prepared in accordance with the standards contained in the most recent publication of 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"). More detailed information will be included in PetroTal's AIF for the year ended December 31, 2022 posted on SEDAR (www.sedar.com) and on PetroTal's website.

Summary of Oil Reserves and Net Present Values as of December 31, 2022

	Company Heavy Oil Reserves (mmbbl)		Future Net Revenue Before Income Taxes Discounted at (in USD Million)				
	Gross	Net	0%	5%	10%	15%	20%
Proved Developed Producing	24.1	24.1	$742	$686	$635	$590	$552
Proved Undeveloped	21.4	21.4	$901	$679	$529	$424	$348
Total Proved	45.5	45.5	$1,643	$1,365	$1,164	$1,014	$900
Probable	51.3	51.3	$2,525	$1,633	$1,124	$814	$614
Total Proved & Probable	96.8	96.8	$4,168	$2,998	$2,288	$1,828	$1,514
Possible	71.6	71.6	$4,512	$2,430	$1,486	$996	$713
Total Proved & Probable & Possible	168.4	168.4	$8,680	$5,428	$3,774	$2,824	$2,227

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

Year-end Forecast	2023	2024	2025	2026	2027	2028
Brent January 1, 2022	$71.46	$69.62	$71.01	$72.44	$73.88	$75.36
Brent January 1, 2023	$84.67	$82.69	$81.03	$81.39	$82.65	$84.29

Year-end Crude Oil Reserves (mmbbl)

Category	2022	2021	Change
Proved Developed Producing	24.1	16.2	49%
Proved Undeveloped	21.4	21.2	1%
Total Proved	**45.5**	**37.4**	**22%**
Probable	51.3	40.5	27%
Total Proved plus Probable	**96.8**	**77.9**	**24%**
Possible	71.6	69.1	4%
Total Proved plus Probable & Possible	**168.4**	**147.0**	**15%**

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

Category	2022	2021	Change
Proved Developed Producing	$635	$250	154%
Proved Undeveloped	$529	$474	12%
Total Proved	**$1,164**	**$724**	**61%**
Probable	$1,124	$665	69%
Total Proved plus Probable	**$2,288**	**$1,389**	**65%**
Possible	$1,485	$932	59%
Total Proved plus Probable & Possible	**$3,773**	**$2,321**	**63%**

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

	December 31, 2022		December 31, 2021	
Category	**US$/sh**	**CAD$/sh**	**US$/sh**	**CAD$/sh**
Proved	$0.90	$1.23	$0.69	$0.88
Proved plus Probable	$1.75	$2.29	$1.23	$1.57
Proved plus Probable & Possible	$2.86	$3.47	$2.00	$2.54

Reserve Life Index ("RLI")

Category	December 31, 2022
Proved	10.1 years
Proved plus Probable	21.5 years
Proved plus Probable & Possible	37.4 years

Future Development Costs

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

Proved	$229 million
Proved plus Probable	$404 million
Proved plus Probable & Possible	$624 million

The future development and abandonment costs are estimates of capital expenditures required in the future for PetroTal to convert the corresponding reserves to proved developed producing reserves.

As a result of the Company's successful drilling program, 2022 1P reserves increased by 21%, to 45.4 mmbbl from 37.4 mmbbl, 2P reserves increased by 24% to 96.7 mmbbl from 77.9 mmbbl, and 3P reserves increased by 14% to 168.3 mmbbl from 147.1 mmbbl. At year-end 2022, Net Present Value (before tax, discounted at 10%) represents $1.2 billion ($25.62/bbl) for 1P reserves, $2.3 billion ($23.66/bbl) for 2P reserves and $3.8 billion ($22.42/bbl) for 3P reserves. Net Present Value (after tax, discounted at 10%) represents $784 million ($17.27/bbl) for 1P reserves, $1.5 billion ($15.60/bbl) for 2P reserves and $2.5 billion ($14.66/bbl) for 3P reserves.

Bretana's reserve life index for 1P and 2P reserves is 10.1 years and 21.5 years, respectively. The cumulative capital invested combined with all future development and abandonment costs represents total funding and development costs of $10.69/bbl for 1P reserves, $5.56/bbl for 2P reserves and $4.33/bbl for 3P reserves.

OOIP estimates for 1P, 2P and 3P reserve categories increased in 2022 from 247 to 329 (33%), 389 to 445 (14%), and 618 to 632 (2%) mmbbl, respectively.

In addition to ongoing development of the Bretana oilfield, there are other prospects within Block 95 and exploration opportunities in Block 107.

7. SIGNIFICANT JUDGEMENTS AND ESTIMATES

Management is required to make judgments, assumptions and estimates that have a significant impact on the Company's financial results. Significant judgments in the Financial Statements include going concern, financing arrangements, impairment indicators, assessment of transfers from Exploration and Evaluation ("E&E") to Property, Plant and Equipment ("PP&E"), leases, derivatives, asset acquisition and joint arrangements. Significant estimates in the Financial Statements include commitments, provision for future decommissioning obligations, recoverable amounts for exploration and evaluation assets and accruals. In addition, the Company uses estimates for numerous variables in the assessment of its assets for impairment purposes, including oil prices, exchange rates, discount rates, cost estimates and production profiles. By their nature, all of these estimates are subject to measurement uncertainty, may be beyond management's control, and the effect on future Financial Statements from changes in such estimates could be significant.

Critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the Financial Statements are included in the Financial Statements and the accompanying notes as of December 31, 2022 and 2021. Additional information about significant judgements and estimates are included in PetroTal's audited Financial Statements for the years ended December 31, 2022 and 2021.

USES OF CRITICAL ACCOUNTING ASSUMPTIONS, ESTIMATES AND JUDGEMENTS

The Company's critical estimates and associated assumptions are based on historical experience and other factors that are considered relevant. Such estimates and assumptions affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from estimates.

The critical estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the same period if the revision affects only that period or in the period of the revision and future periods if the revision affects current and future periods.

Critical estimates and judgements in applying accounting policies that have the most significant effect on the amounts recognized in the Financial Statements are summarized below:

Functional Currency

The functional currency of each of the Company's entities is the United States dollar, which is the currency of the primary economic environment in which the entities operate.

Exploration and Evaluation Assets

The accounting for exploration and evaluation ("E&E") assets requires management to make certain estimates and assumptions, including whether exploratory wells have discovered economically recoverable quantities of reserves. Designations are sometimes revised as new information becomes available. If an exploratory well encounters hydrocarbons, but further appraisal activity is required in order to conclude whether the hydrocarbons are economically recoverable, the well costs remain capitalized as long as sufficient progress is being made in assessing the economic and operating viability of the well. Criteria used in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected additional development activities, commercial evaluation and regulatory matters. The concept of "sufficient progress" is an area of judgement, and it is possible to have exploratory costs remain capitalized for several years while additional drilling is performed, or the Company seeks government, regulatory or partner approval of development plans.

Petroleum and natural gas assets are grouped into cash generating units ("CGUs") identified as having largely independent cash flows and are geographically integrated. The determination of the CGUs was based on management's interpretation and judgement.

Decommissioning Obligations

Decommissioning obligations will be incurred by the Company at the end of the operating life of wells or supporting infrastructure. The ultimate asset decommissioning costs and timing are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques, and experience at other production sites. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The expected amount of expenditure is estimated using a discounted cash flow calculation with a risk-free discount rate. Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed, and the associated costs can be estimated.

Deferred Tax Assets & Liabilities

The estimation of income taxes includes evaluating the recoverability of deferred tax assets based on an assessment of the Company's ability to utilize the underlying future tax deductions against future taxable income prior to the expiration of those deductions. Management assesses whether it is probable that some or all of the deferred income tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income, which in turn is dependent upon the successful discovery, extraction, development and commercialization of oil and gas reserves. To the extent that management's assessment of the Company's ability to utilize future tax deductions changes, the Company would be required to recognize more or fewer deferred tax assets, and future income tax provisions or recoveries could be affected. The measurement of deferred income tax provision is subject to uncertainty associated with the timing of future events and changes in legislation, tax rates and interpretations by tax authorities.

Provisions, Commitments and Contingent Liabilities

Amounts recorded as provisions and amounts disclosed as commitments and contingent liabilities are estimated based on the terms of the related contracts and management's best knowledge at the time of issuing the Financial Statements. The actual results ultimately may differ from those estimates as future confirming events occur.

The Company has one reportable business segment which did not have any critical accounting estimate changes during the past two financial years.

8. RELATED PARTY TRANSACTIONS

The Company had no related party transactions or off-balance sheet arrangements. The Company's key management includes the Directors and Officers.

	Twelve months ended	
	December 31 2022	December 31 2021
Salaries, incentives and short term benefits	1,785	1,505
Director's fees	1,050	369
Share-based compensation	1,615	968
Total	4,450	2,842

The compensation paid to directors during the year ended December 31, 2022 is set forth in the following table.

Name	Compensation Earned	Share-based awards	Non-Equity Incentive Plans	2022 Total	2021 Total
Manuel Pablo Zuniga-Pflucker (*)	450,000	1,100,000	450,000	2,000,000	1,925,074
Mark McComiskey (Chair)	105,000	180,000	—	285,000	70,380
Gary S. Guidry (**)	72,500	73,992	—	146,492	58,650
Ryan Ellson (**)	72,500	73,992	—	146,492	58,650
Gavin Wilson	60,000	60,000	—	120,000	58,650
Eleanor J. Barker	82,000	60,000	—	142,000	58,650
Roger M. Tucker	80,000	60,000	—	140,000	58,650
Jon Harris (***)	17,500	17,500	—	35,000	—
Luis Carranza (***)	17,500	17,500	—	35,000	—
Director Compensation	**957,000**	**1,642,984**	**450,000**	**3,049,984**	**2,288,704**

(*) Mr. Zuniga-Pflucker does not receive compensation fees or share-based awards for his role as a Director.
(**) Directors retired from the Board in September 2022.
(***) Directors joined the Board in September 2022.

9. TAXES

The Company utilizes the liability method of accounting for income taxes. Under the liability method, deferred tax assets and liabilities are recognized using current tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities.

Deferred tax assets are reduced by a valuation allowance if some portion or all of the net deferred tax assets will not be realized. The Company's ability to realize deferred tax assets is assessed throughout the year and a valuation allowance is established, if required. The Company also routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts, including interest where appropriate. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on technical merits.

The Company's effective tax rate is impacted each quarter by the relative pre-tax income (loss) earned by the Company's operations in Canada, U.S., and Peru. The Company is subject to statutory tax rates of 23% in Canada, 21% in the U.S., and 32% in Peru. The Company files federal income tax returns and local income tax returns in the various jurisdictions.

	December 31, 2022	December 31, 2021
Earnings before income taxes	205,917	63,968
Canadian corporate tax rate	23.00 %	23.00 %
Expected income tax expense	47,361	14,713
Increase (decrease) in taxes resulting from:		
Non-deductible expenses and other	1,661	5,984
Tax differential on foreign jurisdictions	18,384	6,223
Recognition of NOL's not previously recognized	(50,031)	(25,968)
Prior year true up and change in tax rates	15	(956)
Provision for income taxes	**17,390**	**(4)**
Current tax expense	501	—
Deferred tax expense (recovery)	16,889	(4)

The following table reconciles the Company's deferred tax asset and liability:

	December 31, 2022	December 31, 2021
Deferred tax assets:		
Finance leases	10	—
Accrued bonus	254	220
Property and equipment	(21)	—
Non-capital losses	855	409
Deferred tax assets	**1,098**	**629**
Deferred tax liabilities:		
Intangibles	1,751	—
Accruals-US	—	(40)
Pre-operation	3,186	—
ROU asset	6,032	—
Asset retirement obligation	4,286	—
Property and equipment	(57,204)	—
Net operating loss carryover-Peru	29,985	—
Temps-other assets	821	—
Temps-other liabilities	(600)	—
Derivatives	(5,643)	—
Deferred tax liabilities	**(17,386)**	**(40)**

The Company recognized the net tax amount related to Net Operating Losses ("NOLs") and deferred tax liabilities in Peru. As at the tax year ended December 31, 2022, the accumulated Peruvian tax losses of $112 million mainly related to Block 95. Also, the Canadian non-capital losses can be carried forward for twenty years for a total of $69 million (the majority is subject to a valuation allowance) in losses, and $1.7 million for US losses. There is generally no carryback period, and the carryover period starts with the taxable year following the loss and continues indefinitely**.** The deferred tax amount not recognized during 2022 was $16 million, compared to $51.9 million in 2021. The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as of December 31, 2022 is approximately $49.6 million, compared to nil in 2021.

The tax rate of the license contracts is 32%; however, due to accumulated tax losses, the Company initially pays an installment of 2% tax on revenue, which is recoverable against any future tax payable.

10. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

GUARANTEES

As of December 31, 2022, the Company holds the following letters of credit guaranteeing its commitments for exploration blocks to Perupetro S.A.:

Block	Beneficiary	Amount	Commitment	Expiration
107	Perupetro S.A.	$1,500	1st exploration well, minimum work 5th exploratory period	December 2023
107	Perupetro S.A.	$1,500	2nd exploration well, minimum work 5th exploratory period	December 2023
		$3,000		

CONTRACTUAL OBLIGATIONS

As of December 31, 2022, the Company has the following contractual obligations:

Contractual Obligation	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Debt	81,445	53,600	27,845	—	—
Trade and other payables	67,195	67,195	—	—	—
Finance lease obligations	19,642	2,567	12,541	4,318	216
Other Obligations (1)	1,309	—	—	—	1,309
Total Contractual Obligations	**169,591**	**123,362**	**40,386**	**4,318**	**1,525**

(1) Deferred share units liability Directors.

11. FORWARD-LOOKING STATEMENTS AND BUSINESS RISKS

FOREIGN EXCHANGE RATE RISK

The Company's functional currency is the United States dollar. Foreign exchange gains or losses can occur on translation of working capital denominated in currencies other than the functional currency of the jurisdiction which holds the working capital item. Excluding the impact of changes in the cross-rates, a 1% fluctuation in translation rates would have nil impact on net income or loss, based on foreign currency balances held at December 31, 2022.

LIQUIDITY RISK

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with its financial liabilities. The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Liquidity is managed through short and long-term cash, debt and equity management strategies. The Company's liquidity risk is impacted by current and future commodity prices. If required, the Company will also consider additional short-term financing or issuing equity in order to meet its future liabilities. Declines in future commodity prices could affect the Company's ability to fund ongoing operations. The current economic environment and SAR-CoV-2 ("COVID-19") has and may continue to have a significant impact on the Company including, but not exclusively:

- material declines in revenue and cash flows as a result of the decline in commodity prices;
- declines in revenue and operating activities due to reduced capital programs and the shut-in of production;
- inability to access financing sources;
- increased risk of non-performance by the Company's customers and suppliers;
- interruptions in operations as the Company adjusts personnel to the dynamic environment; and,
- delivery of oil at the Bayovar port and sale swap price risk.

The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company is not known at this time. Estimates and judgments made by management in the preparation of the financial statements are increasingly difficult and subject to a higher 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 causing a financial loss to the Company. The Company's VAT is primarily for sales tax credits on exploration and drilling expenses incurred in prior years. These credits will be applied to future oil development activities or recovered as per the sales tax recovery legislation currently in effect. The majority of the Company's trade receivable balance relates to oil sales and purchase price adjustments to two customers, being Petroperu, a state-owned company and Novum, an oil trading company. The Company has a long-term sales agreement for oil exports through Brazil, whereby sales are FOB Bretana. Sales through the ONP pipeline are due and payable 240 days after the final delivery of the oil to the Bayovar terminal. The Company's policy is to enter into agreements with customers that are well established and well financed entities in the oil and gas industry such that the level of risk is mitigated. In 2022, 71% of oil sales were to Novum (Brazil export route), 15% were to Petroperu (through the ONP pipeline), and 14% were to Petroperu (Iquitos refinery). The Company has not experienced any material credit losses in the collection of its trade receivables.

Impairment to a financial asset is only recorded when there is objective evidence of impairment and the loss event has an impact 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 that there is no risk on the recoverability and/or applicability of the sales tax credits. Therefore, no impairment to the carrying value of these assets has been estimated. The Company has deposited its cash and cash equivalents with reputable financial institutions, with which management believes the risk of loss to be remote. The maximum credit exposure associated with financial assets is their carrying value. At December 31, 2022, the cash and cash equivalents were held with six different institutions from three countries, mitigating the credit risk of a collapse of one particular bank.

WORKFORCE MAY BE EXPOSED TO WIDESPREAD PANDEMIC

PetroTal's operations are located in areas relatively remote from local towns and villages and represent a concentration of personnel working and residing in close proximity to one another. Should an employee or visitor become infected with a serious illness that has the potential to spread rapidly, this could place the workforce at risk. The 2020/2021 outbreak of the novel coronavirus in China and other countries around the world is one example of such an illness. The Company takes every precaution to strictly follow industrial hygiene and occupational health guidelines. There can be no assurance that this virus or another infectious illness will not impact the Company's personnel and ultimately its operations.

Additional information regarding risk factors including, but not limited to, risks related to political developments in Peru and environmental risks is available in the Company's AIF, a copy of which may be accessed through the SEDAR website (www.sedar.com).

Certain statements contained in this MD&A may constitute forward-looking statements. These statements relate to future events or the Company's future performance, including, but not limited to: PetroTal's business strategy, objectives, strength, focus and outlook, drilling, completions, workovers and other activities including expanding infrastructure and exploring undeveloped acreage and the anticipated costs and results of such activities, environmental remediation and social initiatives, the ability of the Company to achieve drilling success consistent with management's expectations, anticipated future production and revenue, oil production levels, the 2023 capital program and budget, including drilling plans, balance sheet strength, COVID-19 surveillance and control process, hedging program and the terms thereof, and future development and growth prospects. All statements other than statements of historical fact may be forward-looking statements. In addition, statements relating to expected production, reserves, prospective resources, 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. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "intend", "could", "might", "should", "believe" and similar expressions.

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, 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 labor, royalty regimes and exchange rates, 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, the Company's growth strategy, general economic conditions and availability of required equipment and services. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon by investors. These statements speak only as of the date of this MD&A and are expressly qualified, in their entirety, by this cautionary statement.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. These 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), 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 and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. In addition, the Company cautions that current global uncertainty with respect to the spread of the COVID-19 virus and its effect on the broader global economy may have a significant negative effect on the Company. While the precise impact of the COVID-19 virus on the Company remains unknown, rapid spread of the COVID-19 virus may continue to have a material adverse effect on global economic activity, and may continue to result in volatility and disruption to global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company. Please refer to the risk factors identified in the AIF which is available on SEDAR at www.sedar.com.

Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Company cannot guarantee future results, levels of activity, performance, or achievements. The risks and other factors, some of which are beyond the Company's control, could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A.

The forward-looking statements contained in this MD&A are expressly qualified by the foregoing cautionary statement. Subject to applicable securities laws, the Company is under no duty to update any of the forward-looking statements after the date hereof or to compare such statements to actual results or changes in the Company's expectations. Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information should not be used for purposes other than for which it is disclosed herein.

Prospective resources are the quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Estimates of prospective resources included in this document relating to the Osheki prospect are based upon an independent assessment completed by NSAI with an effective date of September 30, 2018 and prepared in accordance with COGE and the standards established by NI 51-101. For additional information about the Company's prospective resources, see the Company's website for the most current press release.

ADDITIONAL INFORMATION

On February 16, 2023, the Company graduated from the TSX Venture Exchange to the Toronto Stock Exchange.

Additional information about PetroTal Corp. and its business activities, including PetroTal's audited Financial Statements for the years ended December 31, 2022 and 2021 are available on the Company's website at www.petrotal-corp.com, and at www.sedar.com, or below:

DIRECTORS
Mark McComiskey
Chair of the Board

Eleanor Barker
Luis Carranza
Jon Harris
Roger Tucker
Gavin Wilson
Manuel Pablo Zuniga-Pflucker

OFFICERS AND SENIOR EXECUTIVES
Manuel Pablo Zuniga-Pflucker
President and Chief Executive Officer

Douglas Urch
EVP and Chief Financial Officer

Dewi Jones
VP Exploration and Development

Glen Priestley
VP Treasury and Planning

Luis Pantoja
General Manager Peru

Guillermo Florez
Deputy General Manager Peru

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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

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Dallas, Texas

TRANSFER AGENT AND REGISTRAR
Computershare Trust Company of Canada
Calgary, Alberta
London, United Kingdom

Equity Stock Transfer
New York, NY

GLOSSARY / ABBREVIATIONS

1P	Proved
2P	Proved plus Probable
3P	Proved plus Probable and Possible
AIF	Annual Information Form
bbl	Barrel
bopd	Barrels of Oil per Day
COGE	Canadian Oil and Gas Evaluation Handbook
COVID-19	SARS-CoV-2
CSR	Community, Social and Regulatory
DD&A	Depletion, Depreciation and Amortization
E&E	Exploration and Evaluation
EIA	Environmental Impact Assessment
ESG	Environmental and Social Governance
FFO	Funds Flow Provided by Operations
G&A	General and Administrative
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
mbbl(s)	Thousand Barrel(s)
MD&A	Management's Discussion and Analysis
mmbbl	Million Barrels
NAV	Net Asset Value
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
NOI	Net Operating Income
NSAI	Netherland Sewell and Associates, Inc.
ONP	North Peruvian Oil Pipeline Agreement
OOIP	Original Oil in Place
PP&E	Property, Plant and Equipment
RLI	Reserve Life Index
SDGs	Sustainable Development Goals
VAT	Value Added Tax

PetroTal

CONSOLIDATED FINANCIAL STATEMENTS
For the years ended December 31, 2022 and 2021

TSX: TAL
AIM: PTAL
OTCQX: PTALF

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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 International Accounting Standards 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"	*Signed "Douglas Urch"*
Manuel Pablo Zuniga-Pflucker	Douglas Urch
President and Chief Executive Officer	Executive VP and Chief Financial Officer

March 29, 2023

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Independent Auditor's Report

To the Shareholders 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, 2022 and 2021, 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 a summary of significant accounting policies (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, 2022 and 2021, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

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 financial statement for the year ended December 31, 2022. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters

Derivative Assets (embedded derivative) — Refer to Note 9 to the financial statements

Key Audit Matter Description

The company has entered into an agreement for the sale of crude oil with Petroleos del Peru (PetroPeru S.A. a state owned company based in Peru). As part of the terms of the agreement, revenue is recognized when the crude oil is delivered to PetroPeru's Saramuro facility. 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 asset 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 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 including the involvement of fair value specialists.

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 estimates, 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

- With the assistance of fair value specialists, independently 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 11 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") using the future net cash flows of the underlying 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 and the related future net cash flows used to evaluate depletion requires management to make significant estimates and assumptions related to future crude oil prices and 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 judgement 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 of the 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, 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.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the financial statements. We are responsible for the direction, supervision and performance 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.

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 29, 2023

PetroTal

CONSOLIDATED BALANCE SHEETS

($ thousands of US Dollars)	Note	December 31 2022	December 31 2021
ASSETS			
Current assets			
Cash	4	104,340	44,919
Restricted cash	4	9,629	23,540
VAT receivable	5	10,555	1,115
Trade and other receivables	6	107,275	2,639
Inventory	7	13,773	22,332
Prepaid expenses	8	5,475	818
Derivative assets	9	12,086	36,723
Total Current Assets		263,133	132,086
Non-current assets			
Restricted cash	4	6,000	6,000
Exploration and evaluation assets	10	7,342	6,051
Property, plant and equipment	11	311,910	251,830
Deferred tax asset	23	1,098	629
VAT receivable	5	1,934	1,692
Derivative assets	9	11,463	—
Total Non-current Assets		339,747	266,202
Total Assets		**602,880**	**398,288**
LIABILITIES AND EQUITY			
Current liabilities			
Trade and other payables	13	67,195	55,015
Lease liabilities	15	2,567	3,849
Short-term debt	12	53,600	24,500
Decommissioning liabilities	14	—	1,403
Total Current Liabilities		123,362	84,767
Non-current liabilities			
Long-term debt	12	27,845	73,700
Long-term derivative liabilities	9	3,179	—
Lease liabilities	15	17,075	13,812
Decommissioning liabilities	14	13,393	20,698
Deferred income tax liabilities	23	17,386	40
Other long-term obligations		1,309	1,014
Total Non-current Liabilities		80,187	109,264
Total Liabilities		203,549	194,031
Equity			
Share capital	16	130,196	126,696
Contributed surplus		6,262	3,215
Retained earnings		262,873	74,346
Total Equity		399,331	204,257
Total Liabilities and Equity		**602,880**	**398,288**

See accompanying notes to the Consolidated Financial Statements

PetroTal

CONSOLIDATED STATEMENTS OF EARNINGS AND OTHER COMPREHENSIVE INCOME

($ thousands of US Dollars, except per share amounts) For the years ended December 31	Note	2022	2021
REVENUES			
Oil revenue, net of royalty	17	327,115	150,227
Total revenues		327,115	150,227
EXPENSES			
Operating		32,954	21,544
Direct transportation		20,622	23,723
General and administrative	18	19,891	14,282
Other expenses	19	978	—
Finance expense	20	20,169	17,838
Commodity price derivatives (gain)	9	(8,231)	(13,036)
Depletion, depreciation and amortization		33,568	21,630
Foreign exchange loss		1,247	278
Total expenses		121,198	86,259
Income before income taxes		**205,917**	**63,968**
Current income tax (expense)		(501)	—
Deferred income tax (expense) recovery	23	(16,889)	4
Net income and comprehensive income		**188,527**	**63,972**
Basic earnings per share		0.22	0.08
Diluted earnings per share		0.21	0.07
Weighted average number of common shares outstanding (000's)			
Basic		845,761	819,286
Diluted		906,710	857,653

See accompanying notes to the Consolidated Financial Statements

PetroTal

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

($ thousands of US Dollars) For the years ended December 31	Note	2022	2021
Share capital			
Balance, beginning of year		126,696	125,302
Exercise of warrants	16	3,500	1,394
Balance, end of period		130,196	126,696
Contributed surplus			
Balance, beginning of year		3,215	1,487
Share-based compensation plan		3,047	1,728
Balance, end of period		6,262	3,215
Retained earnings			
Balance, beginning of year		74,346	10,374
Net income and comprehensive income		188,527	63,972
Balance, end of period		262,873	74,346

See accompanying notes to the Consolidated Financial Statements

PetroTal

CONSOLIDATED STATEMENTS OF CASH FLOWS

($ thousands of US Dollars) For the years ended December 31	Note	2022	2021
Cash flows from operating activities			
Net income		188,527	63,972
Adjustments for:			
Depletion, depreciation and amortization		33,568	21,630
Accretion of decommissioning obligations	14	897	530
Share-based compensation plan		3,342	2,361
Commodity price unrealized derivatives loss (gain)	9	9,256	(11,574)
Finance expenses		17,419	14,132
Deferred income tax expense (recovery)	23	16,889	(4)
Settlement of abandonment liabilities	14	(4,917)	(2,871)
Changes in non-cash working capital:			
- Receivables and taxes		(114,318)	10,283
- Advances and prepaid expenses		(1,204)	7,122
- Inventory		6,240	(12,943)
- Trade payables and other		12,676	(13,415)
- Commodity price realized derivatives	9	7,097	(1,462)
Cash paid for income taxes		(3,453)	(305)
Net cash provided by operating activities		172,019	77,456
Cash flows from investing activities			
Property, plant and equipment additions	11	(92,912)	(81,296)
Exploration and evaluation asset additions	10	(1,291)	(895)
Non-cash changes in working capital		(531)	5,997
Net cash used in investing activities		(94,734)	(76,194)
Cash flows from financing activities			
Interest and fees paid		(11,300)	(6,000)
Net proceeds from exercise of warrants	16	3,500	1,394
Net funds (repaid) received from bond issuance	12	(20,000)	90,900
Settlement of restructuring agreement	9	—	(16,626)
Funds repaid to assistance programs	12	—	(2,900)
Payment of current lease liabilities	15	(3,974)	(2,647)
Net cash (used in) provided by financing activities		(31,774)	64,121
Increase in cash for the period		45,511	65,383
Cash, beginning of period		44,919	9,076
Restricted cash (current)	4	13,910	(29,540)
Cash, end of the period		**104,340**	**44,919**

See accompanying notes to the Consolidated Financial Statements

1. CORPORATE INFORMATION

PetroTal Corp. (the "Company" or "PetroTal") is a publicly-traded energy company incorporated and domiciled in Canada. The Company is engaged in the exploration, appraisal and development of oil and natural gas in Peru, South America. The Company's registered office is located at 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada.

These Consolidated Financial Statements (the "Financial Statements") have been prepared on a going concern basis, which assumes that the Company will continue its operations for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of business.

The Company evaluated subsequent events and transactions that occurred after the balance sheet date up to the date that the Financial Statements were issued.

These Financial Statements were approved for issuance by the Company's Board of Directors on March 29, 2023, on the recommendation of the Audit Committee.

2. BASIS OF PREPARATION

STATEMENT OF COMPLIANCE

The Company prepares its annual Financial Statements in accordance with International Financial Reporting Standards ("IFRS").

BASIS OF MEASUREMENT

These Financial Statements have been prepared on a historical cost basis except for certain financial instruments that have been measured at fair value. In addition, these Financial Statements have been prepared using the accrual basis of accounting.

PRINCIPLES OF CONSOLIDATION

The Company's 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 Company's, using consistent accounting practices.

Inter-company balances and transactions, and any unrealized gains arising from inter-company transactions with the Company's subsidiaries, are eliminated on consolidation.

The entities included in the Company's Financial Statements are PetroTal Corp. and its 100% owned subsidiaries PetroTal USA Corp., PetroTal LLC, PetroTal Energy International (Peru) Holdings B.V., PetroTal Peru B.V., Petrolifera Petroleum Del Peru S.R.L. and PetroTal Peru S.R.L.

USES OF ACCOUNTING ASSUMPTIONS, ESTIMATES AND JUDGEMENTS

The preparation of the Company's Financial Statements requires management to make judgement, estimates, and assumptions that affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and other factors that are considered relevant. Actual results may differ from estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the same period if the revision affects only that period or in the period of the revision and future periods if the revision affects current and future periods.

Estimates and critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the Financial Statements are summarized below:

Functional Currency

The functional currency of each of the Company's entities is the United States dollar, which is the currency of the primary economic environment in which the entities operate.

Exploration and Evaluation Assets

The accounting for exploration and evaluation ("E&E") assets requires management to make certain estimates and assumptions, including whether exploratory wells have discovered economically recoverable quantities of reserves. Designations are sometimes revised as new information becomes available. If an exploratory well encounters hydrocarbons, but further appraisal activity is required in order to conclude whether the hydrocarbons are economically recoverable, the well costs remain capitalized as long as sufficient progress is being made in assessing the economic and operating viability of the well. Criteria used in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected additional development activities, commercial evaluation and regulatory matters. The concept of "sufficient progress" is an area of judgement, and it is possible to have exploratory costs remain capitalized for several years while additional drilling is performed, or the Company seeks government, regulatory or partner approval of development plans.

Petroleum and natural gas assets are grouped into cash generating units ("CGUs") identified as having largely independent cash flows and are geographically integrated. The determination of the CGUs was based on management's interpretation and judgement.

Decommissioning Obligations

Decommissioning obligations will be incurred by the Company at the end of the operating life of wells or supporting infrastructure. The ultimate asset decommissioning costs and timing are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques, and experience at other production sites. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The expected amount of expenditure is estimated using a discounted cash flow calculation with a risk-free discount rate. Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed, and the associated costs can be estimated.

Deferred Tax Assets & Liabilities

The estimation of income taxes includes evaluating the recoverability of deferred tax assets based on an assessment of the Company's ability to utilize the underlying future tax deductions against future taxable income prior to the expiration of those deductions. Management assesses whether it is probable that some or all of the deferred income tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income, which in turn is dependent upon the successful discovery, extraction, development and commercialization of oil and gas reserves. To the extent that management's assessment of the Company's ability to utilize future tax deductions changes, the Company would be required to recognize more or fewer deferred tax assets, and future income tax provisions or recoveries could be affected. The measurement of deferred income tax provision is subject to uncertainty associated with the timing of future events and changes in legislation, tax rates and interpretations by tax authorities.

Provisions, Commitments and Contingent Liabilities

Amounts recorded as provisions and amounts disclosed as commitments and contingent liabilities are estimated based on the terms of the related contracts and management's best knowledge at the time of issuing the Financial Statements. The actual results ultimately may differ from those estimates as future confirming events occur.

SIGNIFICANT ACCOUNTING POLICIES

a. **Cash and Restricted Cash**

   Cash includes deposits held with banks in Canada, the United States and Peru that are available on demand and highly liquid. The Company's restricted cash is cash reserved for letters of credit guaranteeing the Company's commitments for the 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. The restricted cash is not available for the Company's immediate or general business use.

b. **Property, Plant and Equipment**

   Property, plant and equipment ("PP&E") is recorded at cost less accumulated depreciation. Depreciation begins when the asset is put into service and is calculated annually using the straight-line method. The cost of maintenance and repairs is charged to expense as incurred. The cost of significant renewals and improvements is added to the carrying amount of the respective asset. When assets are retired, or otherwise disposed of, the cost and related accumulated depreciation are removed from the balance, and any resulting gain or loss is reflected in the consolidated statements of earnings and comprehensive income.

   When commercial production in an area has commenced, petroleum properties, excluding surface costs are depleted using the unit-of-production method over their proved plus probable reserve life. Proved plus probable reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of future crude oil prices, reserves and future operating and development costs that affect unit-of-production calculations are accounted for on a prospective basis.

c. 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 judgements 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.

d. Impairment

Financial assets carried at amortized cost

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, the Company recognizes an impairment loss in net earnings (loss). Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

Non-financial assets

At each reporting date, the carrying amounts of the Company's non-financial assets are reviewed to determine whether there is indication of impairment, except for E&E assets, which are reviewed when circumstances indicate impairment may exist. If there is indication of impairment, the asset's recoverable amount is estimated and compared to its carrying value.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the cash-generating unit). The recoverable amount of an asset or a CGU is the greater of its value in use or its fair value less costs to sell. The Company's CGUs are not larger than a segment. In assessing both fair value less costs to sell and value in use, the estimated future cash flows are discounted to their present value using an after-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. An impairment loss is recognized if the carrying amount of an asset or its CGU (Company has a single segment) exceeds its estimated recoverable amount. Impairment losses are recognized in net earnings (loss). Fair value less costs to sell and value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

E&E assets are tested for impairment when they are transferred to petroleum properties and also if facts and circumstances suggest that the carrying amount of E&E assets may exceed the recoverable amount. Impairment indicators are evaluated at a CGU level. Indication of impairment includes:

- Expiry or impending expiry of lease with no expectation of renewal;
- Lack of budget or plans for substantive expenditures on further E&E;
- Cessation of E&E activities due to a lack of commercially viable discoveries; and
- Carrying amounts of E&E assets are unlikely to be recovered in full from a successful development project.

Impairment losses recognized in prior years are assessed at each reporting date for indication that the loss has decreased or no longer exists. An impairment loss may be reversed if there has been a change in the estimates used to determine the recoverable amount. 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 and depreciation or amortization, if no impairment loss had been recognized.

e. Inventory

Inventory consists of crude oil and supplies to be used in the production and exploration activities, and is measured at the lesser of cost and net realizable value. The cost of crude oil inventory includes all costs incurred in bringing the inventory to its storage location. These costs, including operating expenses, royalties, transportation and depletion, are capitalized in the ending inventory balance. The cost of the inventory is recognized using the weighted average method.

f. Financial Instruments

On initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods depends on the classification of the financial instrument:

- Fair value through profit or loss - subsequently carried at fair value with changes recognized in net earnings (loss). Financial instruments under this classification include cash and cash equivalents, and derivative commodity contracts;
- Fair value through other comprehensive income - transaction costs under this classification are expensed as incurred. Financial instruments under this classification include derivative assets and liabilities where hedge accounting is applied; and
- Amortized cost - subsequently carried at amortized cost using the effective interest rate method. Financial instruments under this classification includes accounts receivable, accounts payable and accrued liabilities and long-term debt.

IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Derivative instruments are not used for trading or speculative purposes. The Company does not designate financial derivative contracts as effective accounting hedges, and thus does not apply hedge accounting. As a result, the Company's policy is to classify all financial derivative contracts at fair value through profit or loss and to record them on the Consolidated Balance Sheet at fair value with a corresponding gain or loss in net earnings (loss). Attributable transaction costs are recognized in net earnings (loss) when incurred. The estimated fair value of all derivative instruments is based on quoted market prices and/or third-party market indications and forecasts.

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not closely related to those of the host contract; when the terms of the embedded derivatives are the same as those of a freestanding derivative; and when the combined contract is not measured at fair value through profit or loss. The timing of the expected delivery to the final point of sale drives the value of the embedded derivative in the Petroperu contract, as the fair value of the derivative depends on the oil price at the time of the expected sale date at the final point of sale. Refer to Note 9 for the classification and measurement of these financial instruments.

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 and are included in the Company's balance sheet. The Company initially measures financial instruments at fair value.

g. Exploration and Evaluation Assets

E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. These costs include acquisition costs, exploration costs, geological and geophysical costs, decommissioning costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are expensed as incurred.

At each reporting date, the carrying amounts of the Company's exploration and evaluation assets are reviewed to determine whether there is any indication that those assets are impaired. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment, if any. The recoverable amount is the greater of its value in use and its fair value less costs to sell. If the recoverable amount of an asset is estimated to be less than its carrying amount, the carrying amount of the asset is reduced to its recoverable amount and the impairment loss is recognized in profit or loss for the year. The exploration and evaluation phase of a particular project is completed when both the technical feasibility and commercial viability of extracting oil or gas are demonstrable for the project or there is no prospect of a positive outcome for the project. Exploration and evaluation assets with commercial reserves will be reclassified to development and production assets and the carrying amounts will be assessed for impairment and adjusted (if appropriate) to their estimated recoverable amounts.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to property, plant and equipment, where they are depleted. Exploration and evaluation assets are not amortized during the exploration and evaluation stage. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to comprehensive income (loss) as impairment of exploration and evaluation assets.

h. Decommissioning Obligations

The Company recognizes a decommissioning liability in relation to the evaluation and exploration assets and to property, plant and equipment, in the period in which a reasonable estimate of the fair value can be made of the statutory, contractual, constructive or legal liabilities associated with the retirement of the oil and gas properties, facilities and pipelines. The amount recognized is the estimated cost of decommissioning, discounted to its present value using a discount rate. The estimates are reviewed periodically. Changes in the provision resulting from changes to the timing of expenditures, costs or risk-free rates are dealt with prospectively by recording an adjustment to the provision and a corresponding adjustment to property, plant and equipment or exploration and evaluation assets. The unwinding of the discount on the decommissioning provision is charged to the consolidated statements of earnings and comprehensive income. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and the remaining balance of the actual costs is recorded in the consolidated income statement.

i. Income Taxes

Income tax expense is comprised of current and deferred tax. Current tax and deferred tax are recognized in net income or loss except to the extent that it relates to a business combination or items recognized directly in equity or in other comprehensive income or loss. Current income taxes are recognized for the estimated income taxes payable or receivable on taxable income or loss for the current year and any adjustment to income taxes payable in respect of previous years. Current income taxes are determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date. Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base, except for taxable temporary differences arising on the initial recognition of goodwill and temporary differences arising on the initial recognition of an asset or liability in a transaction which is not a business combination and at the time of the transaction affects neither accounting nor taxable profit or loss. Recognition of deferred tax assets for unused tax losses, tax credits and deductible temporary differences is restricted to those instances where it is probable that future taxable profit will be available against which the deferred tax asset can be utilized. At the end of each reporting period the Company reassesses unrecognized deferred tax assets. The Company recognizes a previously unrecognized deferred tax asset to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

j. Revenue Recognition

Under IFRS 15, revenue is recognized when a customer obtains control of the goods or services as stipulated in a performance obligation. Determining whether the timing of the transfer of control is at a point in time or over time requires judgement and can significantly affect when revenue is recognized. In addition, the entity must also determine the transaction price and apply it correctly to the goods or services contained in the performance obligation.

The Company's revenue is derived exclusively from contracts with customers. Revenue associated with the sale of crude oil and gas is measured based on the consideration specified in contracts with customers. Revenue from contracts with customers is recognized when the Company satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of the good or service. The transfer of control of oil and gas usually coincides with title passing to the customer and the customer taking physical possession. Company mainly satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

Revenues from the sale of crude oil and gas are recognized by reference to actual volumes delivered at contracted delivery points and prices. Prices are determined by reference to quoted market prices in active markets, adjusted according to specific terms and conditions applicable per the sales contracts. Revenues are recognized prior to the deduction of transportation costs. Revenues are measured at the fair value of the consideration received.

k. Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity.

l. Foreign Currency Translation

Transactions in foreign currencies are initially translated into the functional currency using the exchange rate on the transaction date. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the consolidated statements of earnings and comprehensive income. Each subsidiary in the group is measured using the currency of the primary economic environment in which the entity operates, which is its functional currency.

m. Earnings per Share

The Company presents basic and diluted earnings per share (“EPS”) data for its common shares (the “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 determined by dividing the net profit or loss attributable to common shareholders by the weighted average number of Common Shares outstanding during the year, plus the weighted average number of Common Shares that would be issued on conversion of all dilutive potential Common Shares into Common Shares. Those potential Common Shares comprise share options granted.

n. 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.

o. Business Combinations

The Company adopted the amendments to IFRS 3 – Business Combinations. The amendments introduced an optional concentration test, narrowed the definitions of a business and outputs, and clarified that an acquired set of activities and assets must include an input and a substantive process that together significantly contribute to the ability to create outputs.

3. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

NEW ACCOUNTING STANDARDS ISSUED

New accounting standards and interpretations were issued and mandatory starting January 1, 2022. The new standards and interpretations shown below did not have a significant impact on the Company's Financial Statements upon adoption.

- IAS 16 – Property, Plant and Equipment – Effective January 1, 2022, the amendments prohibit a company from deducting from the cost of PP&E amounts received from selling items produced while the company is preparing the asset for its intended use. Instead, a company will recognize such sales proceeds and related cost in profit or loss.
- IAS 37 – Provisions, Contingent Liabilities and Contingent Assets – Effective January 1, 2022, the amendments specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous.

NEW ACCOUNTING STANDARDS ISSUED BUT NOT EFFECTIVE

New accounting standards and interpretations were issued and are mandatory for accounting periods after January 1, 2023. Certain of the new accounting standards and interpretations, which are not expected to have a significant impact on the Company's Financial Statements upon adoption, are as follows:

- IAS 1 – Disclosure of Accounting Policies – Effective January 1, 2023, the amendments require an entity to disclose its material accounting policies, instead of its significant accounting policies, while providing guidance on how entities can identify material accounting policy information and examples of when accounting policy information is likely to be material.
- IAS 1 – Presentation of Financial Statements – Effective January 1, 2023, the amendments clarify the requirements for the presentation of liabilities as current or non-current in the balance sheet.
- IAS 8 – Definition of Accounting Estimates – Effective January 1, 2023, the amendments distinguish how an entity should present and disclose different types of accounting changes in its financial statements and provides updated definitions to changes in accounting estimates to assist issuers in assessing between a change in accounting policy and a change in accounting estimate.
- IAS 12 – Income Taxes – Effective January 1, 2023, the amendments clarify that the initial recognition exemption provided in IAS 12.15(b) and IAS 12.24 does not apply to transactions in which both deductible and taxable temporary differences arise on initial recognition that result in the recognition of equal deferred tax assets and liabilities.

4. CASH AND RESTRICTED CASH

The following table sets out cash and restricted cash balances held in different currencies:

	December 31 2022	December 31 2021
Balances held in:		
US dollars	117,378	73,057
Peruvian soles	113	110
English pounds	2,457	1,258
Canadian dollars	21	34
Total	119,969	74,459
Represented as:		
Cash	104,340	44,919
Restricted cash current	9,629	23,540
Restricted cash non-current	6,000	6,000

Current restricted cash of $9.6 million, is primarily related to the social fund, letters of credit bank guarantees, and hedge deposits. The $6 million of non-current restricted cash is related to permitted hedging programs (see Note 9). The social fund was formally recognized in Q3 where 2.5% of the value of the monthly oil produced in Bretana's Block 95, less transportation, is set aside for the benefit of local communities. The Company is currently in negotiations with the Peruvian government and communities to finalize the social fund framework and an amendment to the license agreement, to be effective and retroactive to January 1, 2022. During the year, the Company accrued $6.3 million in social fund expense (see Note 17), of which $1.2 million was paid before the end of December 31, 2022.

5. VAT RECEIVABLES

	December 31 2022	December 31 2021
VAT receivable - current	10,555	1,115
VAT receivable - non-current	1,934	1,692
Total VAT receivables	12,489	2,807

Valued Added Tax ("VAT") in Peru is levied on the purchase of goods and services and is recoverable on sales of goods and services. The Company recovered $28.7 million during the twelve months ended December 31, 2022 and expects to recover $10.6 million in the short-term based on its estimated sales.

6. TRADE AND OTHER RECEIVABLES

	December 31 2022	December 31 2021
Trade receivables	105,647	441
Other receivables	1,628	2,198
Total trade and other receivables	107,275	2,639

As at December 31, 2022, trade receivables represent revenue related to the sale of oil during the period. The balance is mainly comprised of $74 million due from Petroperu. In addition, $31 million is for export sales through Brazil.

In November 2022, PetroTal reached an agreement with Petroperu for repayment of $64 million owing to the Company, of which $10 million was collected in 2022. The monthly installments are expected to be collected by August 2023. No credit losses on the Company's trade receivables have been incurred.

7. INVENTORY

	December 31 2022	December 31 2021
Oil inventory	2,389	12,222
Materials, parts and supplies	11,384	10,110
Total inventory	13,773	22,332

Oil inventory consists of the Company's oil barrels, which are valued at the lower of cost or net realizable value. Costs include operating expenses, royalties, transportation, and depletion associated with production. Costs capitalized as inventory will be expensed when the inventory is sold. As at December 31, 2022, the oil inventory balance of $2.4 million consists of 106,621 barrels of oil valued at $22.40/bbl (December 31, 2021: $12.2 million, based on 432,075 barrels at $28.29/bbl). Materials, parts and supplies, including diluent, are expected to be consumed in the short-term.

8. PREPAID EXPENSES

	December 31 2022	December 31 2021
Advances to contractors	—	21
Prepaid expenses and other	5,475	797
Total advances and prepaid expenses	5,475	818

As at December 31, 2022, prepaid expenses were comprised of $4.4 million in Peruvian income tax prepaid and $1.1 million in insurance, prepaid services for consultants, and other related services.

9. RISK MANAGEMENT

	December 31, 2022		December 31, 2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and restricted cash	119,969	119,969	74,459	74,459
Trade and other receivables	107,275	107,275	2,639	2,639
Short-term derivative assets	12,086	12,086	36,723	36,723
Long-term derivative assets	11,463	11,463	—	—
Short and long-term debt	81,445	82,000	98,200	98,200
Trade and other payables	67,195	67,195	55,015	55,015

The table above details the Company’s carrying value and fair value of financial instruments including cash and restricted cash, trade and other receivables, derivatives, short and long-term debt, and trade and other payables, all of which are classified as financial assets and liabilities and reported at amortized cost or fair value. The Company is exposed to various financial risks arising from normal-course business exposure. These risks include market risks relating to foreign exchange rate fluctuations and commodity price risk as well as liquidity.

COMMODITY PRICE DERIVATIVES

The derivative asset is classified as a Level 2 fair value measurement. The Petroperu Saramuro agreement, signed with Petroperu during 2021, includes a clause for the purchase price adjustment. The initial sales price is based on the arithmetic average of the ICE Brent Crude 8-month forward price. The realized price is based on the tender price of the oil that is sold at the Bayovar terminal. The purchase price adjustment is the realized price less the initial sales price. If the purchase price adjustment is negative, the Company will compensate Petroperu for the amount, multiplied by the volume sold or arranged by Petroperu. If the purchase price adjustment is positive, the Company will be compensated by Petroperu.

The fair value of the embedded derivative, considering an average future Brent price marker differential, was recorded as a gain (loss) on commodity price derivatives at December 31, 2022.

Net derivative asset at January 1, 2022	36,724
Cash settlements	3,585
Cash to be received	(28,171)
Realized gain	17,488
Unrealized gain (loss)	(9,256)
Net derivative asset at December 31, 2022	20,370
Represented as:	
Short-term derivative assets	12,086
Long-term derivative assets	11,463
Short-term derivative liabilities	—
Long-term derivative liabilities	(3,179)

Sales delivery / Executed month	Expected settlement month	Volume mbbls	Price range $/bbl	Hedged range $/bbl	Derivative Asset
Peru Embedded Derivatives (a)					
Jan-21 to Feb-22	Jun-23 to May-25	2,422	55.32 to 85.26	75.42 to 84.76	17,635
Corporate Derivatives Hedging (b)					
Sep-22	Jan-23 to Sep-23	430	—	80.00	2,735
				Net Derivative Asset	**20,370**

a) Embedded derivative related to original Petroperu sales agreement.
b) Corporate hedge program to cover a portion of 2022 oil production.

During the twelve months ended December 31, 2022, 0.9 million barrels have been sold by Petroperu. 2.4 million barrels remain in the pipeline or storage tanks, awaiting final sale by Petroperu.

FOREIGN EXCHANGE RATE RISK

The Company's functional currency is the United States dollar. Foreign exchange gains or losses can occur on translation of working capital denominated in currencies other than the functional currency of the jurisdiction which holds the working capital item. Excluding the impact of changes in the cross-rates, a 1% fluctuation in translation rates would have nil impact on net income or loss, based on foreign currency balances held at December 31, 2022.

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 impacted by current and future commodity prices. If required, the Company will also consider additional short-term financing or issuing equity in order to meet its future liabilities. 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 as a result of the decline in commodity prices;
- declines in revenue and operating activities due to reduced capital programs and constrained oil production;
- inability to access financing sources;
- increased risk of non-performance by the Company's customers and suppliers;
- interruptions in operations as the Company adjusts personnel to the dynamic environment; and,
- delivery of oil at Bayovar port and sale swap price risk.

Estimates and judgements 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 causing a financial loss to the Company. The Company's VAT is primarily for sales tax credits on exploration and drilling expenses incurred in prior years. These credits will be applied to future oil development activities or recovered as per the sales tax recovery legislation currently in effect. The Company's trade receivable balance relates to oil sales and purchase price adjustments to two customers, being Petroperu, a state-owned company and Novum, an oil trading company. The Company has a long-term sales agreement for oil exports through Brazil, whereby sales are FOB Bretana. Sales through the ONP pipeline are due and payable 240 days after the final delivery of the oil to the Bayovar terminal. The Company's policy is to enter into agreements with customers that are well established and well financed entities in the oil and gas industry such that the level of risk is mitigated. In 2022, 71% of oil sales were to Novum (Brazil export route), 15% were to Petroperu (through the ONP pipeline), and 14% were to Petroperu (Iquitos refinery). The Company has not experienced any material credit losses in the collection of its trade receivables.

Impairment to a financial asset is only recorded when there is objective evidence of impairment and the loss event has an impact 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 that there is no risk on the recoverability and or applicability of the sales tax credits. Therefore, no impairment to the carrying value of these assets has been estimated. The Company has deposited its cash and cash equivalents with reputable financial institutions, with which management believes the risk of loss to be remote. The maximum credit exposure associated with financial assets is their carrying value. At December 31, 2022, the cash and cash equivalents were held with six different institutions from three countries, mitigating the credit risk of a collapse of one particular bank.

10. EXPLORATION AND EVALUATION ASSETS

The following table sets out a continuity of Exploration and Evaluation Assets:

Balance at January 1, 2021	5,156
Additions	895
Balance at December 31, 2021	6,051
Additions	1,291
Balance at December 31, 2022	7,342

The Company determined there were no impairment indicators of the exploration and evaluation assets balance at December 31, 2022 and December 31, 2021.

11. PROPERTY, PLANT AND EQUIPMENT

	Petroleum Interests	Right of Use Asset (Power Plant)	Other Assets	Total
Balance at January 1, 2021	168,548	—	691	169,239
Additions	80,831	21,387	465	102,683
Additions to decommissioning obligations	3,271	—	—	3,271
Depletion, depreciation and amortization	(21,641)	(1,199)	(523)	(23,363)
Balance at December 31, 2021	231,009	20,188	633	251,830
Additions	91,348	5,894	2,933	100,175
Revisions to decommissioning obligations	(4,688)	—	—	(4,688)
Revisions to right of use asset	—	(4,158)	—	(4,158)
Depletion, depreciation and amortization	(29,390)	(1,212)	(647)	(31,249)
Balance at December 31, 2022	288,279	20,712	2,919	311,910

As at December 31, 2022, $0.7 million of the depreciation, depletion and amortization expense was recorded as inventory (December 31, 2021: $2.8 million).

During 2022, the Company entered into two new office leases, one in Houston, Texas and one in Lima, Peru. The Houston lease is for a term of 6.2 years with a present value of $0.5 million and the Lima lease is for 5 years with a present value of $0.8 million, both of which are reported as Other Assets.

During the year, the Company leased two additional generators for five years with a present value of $5.9M from the same supplier that provides turnkey power generation equipment services with monthly lease payments of $0.1 million. The Company has the option to buy the equipment. Also, at the same time, the Company amended the original lease agreement reducing the lease term for six generators which resulted in a $4.2M reduction to the right of use asset.

The Company determined there were no impairment indicators of the property, plant and equipment balance at December 31, 2022 and December 31, 2021.

12. SHORT AND LONG-TERM DEBT

On February 2, 2021, the Company completed a 3-year senior secured bond with a face value of $100 million issued at a 5% discount for total consideration of $95 million. The bonds bear interest at 12% and interest is due semi-annually. The Company incurred deferred financing costs of $4.1 million, which are amortized using the effective interest method over the remaining term of the debt. The Company, at its option, may redeem the bonds prior to maturity. Each bondholder shall have a right of prepayment and the issuer shall have a right of redemption, in each case at a price of 101% - 106% of nominal amount (plus accrued but unpaid interest on the redeemed bonds) during a period of 30 calendar days starting at the first anniversary of the issue date. In accordance with the agreement, the net proceeds of $90.9 million from the bonds were initially applied towards:

(i) $16.6 million, plus accrued interest at 6.12%, for payment of all amounts outstanding under the Petroperu restructuring agreement;
(ii) $2.9 million for repayment of the Peruvian Reactiva assistance program;
(iii) $20 million restricted for the acquisition of qualified hydrocarbon assets;
(iv) $15 million for the permitted hedging programs; and,
(v) Remaining amount for the Bretana oil field development.

On April 1, 2022, the Company elected to repay $20 million from restricted cash to bondholders pursuant to the call option set out in the bond agreement. In addition, the Company recognized $1.3 million of additional amortization and interest expense during Q1 2022 related to the bond's present value determination. The remaining bond principal repayments are $25 million in February 2023, $25 million in August 2023 and $30 million in February 2024.

US Dollar denominated debt - senior secured bonds		
12% due February 16, 2024	Effective rate 15.7%	80,000
Less: unamortized financing cost		(2,155)
Interest payable		3,600
Balance at December 31, 2022		81,445
Represented as:		
Short-term debt		53,600
Long-term debt		27,845

In accordance with the terms of the bond agreement, the bonds are secured by all assets of the Company, and the Company is required to maintain the following financial ratios:

Covenant	Ratio	Description
a)	Liquidity	Cash amount not less than interest payable for the next 12 months
b)	Equity	Equity to Total Assets minimum rate of 40%
c)	Leverage	Net debt to Adjusted EBITDA does not exceed the ratio of 2:1

The Company met all covenants as at December 31, 2022. No distributions to shareholders are permitted until the bonds are relinquished.

Fair Value

The short and long-term debt fair value estimate is $82.0 million. The fair value of the Company's debt on December 31, 2022 (Note 9), was determined by reference to valuation inputs under Level 2 of the fair value hierarchy.

13. TRADE AND OTHER PAYABLES

	December 31 2022	December 31 2021
Trade payables	32,177	26,888
Accrued payables and other obligations	35,018	28,127
Total trade and other payables	67,195	55,015

As at December 31, 2022 and December 31, 2021, trade payables and other payables are primarily related to the drilling and completion of wells and construction of production processing facilities. The other obligations is mainly related to the 2.5% social fund for the benefit of local communities.

14. DECOMMISSIONING LIABILITIES

Balance at January 1, 2021	21,171
Additions	3,165
Revisions to decommissioning liabilities	106
Expenditures	(2,871)
Accretion	530
Balance at December 31, 2021	22,101
Additions	1,916
Revisions to decommissioning liabilities	(6,604)
Expenditures	(4,917)
Accretion	897
Balance at December 31, 2022	13,393
Represented as:	
Current	—
Non-current	13,393

The undiscounted uninflated value of estimated decommissioning liabilities is $30.2 million ($29.4 million in 2021). The present value of the obligations was calculated using an average risk-free rate of 6.6% (December 31, 2021: 3.6%) 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 table above sets out the continuity of decommissioning obligations.

15. CURRENT AND NON-CURRENT LEASE LIABILITIES

The Company commenced a seven-year service contract with a supplier that provides turnkey power generation equipment services. The Company has the option to buy the equipment on year five for $5.5 million. The incremental borrowing rate used to measure the lease liabilities was 7.5% for the dollar denominated lease. In Q3 2022, the Company entered into two new office leases, one in Houston, Texas and one in Lima, Peru, with lease termination dates of August 2028 and August 2027, respectively (see Note 11).

Lease liabilities at January 1, 2021	228
Net additions	16,721
Interest on leases	712
Lease liabilities at December 31, 2021	17,661
Additions	7,263
Revisions	(2,332)
Payments	(3,974)
Interest on leases	1,024
Lease liabilities at December 31, 2022	19,642
Represented as:	
Current liability	2,567
Non-current liability	17,075

As at December 31, 2022, total lease liabilities have the following minimum undiscounted annual payments:

Year	
2023	4,989
2024	5,014
Thereafter	11,139
Total	21,142

16. SHARE CAPITAL

Authorized share capital consists of an unlimited number of common shares without nominal or par value. The holders of common shares are entitled to one vote per share and are entitled to receive dividends as recommended by the Board of Directors after repayment of the bonds.

	Thousands of common shares	**Share Capital**
Balance at January 1, 2021	816,167	125,302
Vesting of performance share units	4,973	—
Warrants exercised	7,057	1,394
Balance at December 31, 2021	828,197	126,696
Vesting of performance share units	8,050	—
Warrants exercised	25,962	3,500
Balance at December 31, 2022	862,209	130,196

PERFORMANCE AND INVESTORS' WARRANTS

The performance warrants were all exercised prior to their expiration date of December 18, 2022. The warrants were fully vested and converted into an equal number of shares, pursuant to the exercise price of $0.187 per share.

The investor warrants were granted in connection with the brokered private placement offering on June 18, 2020. Investors received one common share and one half of one warrant allowing the subscriber to purchase additional shares until June 17, 2023, at 16 pence/share upon presentation of a full warrant. The following table sets out a continuity of outstanding warrants:

	Performance Warrants	Investor Warrants
Balance at January 1, 2021	25,750,000	70,601,946
Warrants exercised	(3,203,650)	(3,852,941)
Balance at December 31, 2021	22,546,350	66,749,005
Warrants exercised	(22,546,350)	(6,873,318)
Balance at December 31, 2022	—	59,875,687

SHARE-BASED COMPENSATION

The Company has granted performance share units ("PSUs") to employees and deferred share units ("DSUs") to directors. The grant date fair value of PSUs granted to employees is recognized as share-based compensation expense with a corresponding increase in contributed surplus over the vesting period. The Company granted PSUs to employees in accordance with the provisions of the Company's PSU plan. The PSUs either vest after three years or equally over three years and each PSU will entitle the holder to acquire between zero and two common shares of the Company, subject to the achievement of performance conditions relating to the Company's total shareholder return, net asset value and certain production, environmental, safety and operational milestones. The fair value of the PSUs is determined through a combination of Black-Scholes and probability weighted models. The following table details the terms of the PSUs outstanding as at December 31, 2022:

	2022 Plan Share Units	2021 Plan Share Units
Vest date 3 years from grant date, exchangeable for up to 2 shares	3,169,560	6,467,416
Vests equally over 3 years from grant date, exchangeable for up to 2 shares	457,728	311,327
Vests equally over 3 years from grant date, exchangeable for up to 1-1.5 shares	1,422,331	694,026
Total units	5,049,619	7,472,769

The following assumptions were used for the Black-Scholes valuation of the PSUs granted:

	2022 Plan	2021 Plan
Risk-free interest rate	2.0 %	2.0 %
Expected Life	1-3 years	1-3 years
Annualized volatility	50 %	50 %

For the twelve months ended December 31, 2022, the Company recognized $4.1 million of share-based compensation expense in general and administrative expense (December 31, 2021: $1.2 million).

The Company issued DSUs to directors of the Company, pursuant to the Company's DSU plan and has 2,651,754 DSUs outstanding at December 31, 2022. The DSUs are fully vested and are redeemable upon a holder ceasing to be a director of PetroTal. No common shares will be issued under the DSU plan, as they are settled in cash at the prevailing market price and valued at the closing share price on the reporting date. For the twelve months ended December 31, 2022, the Company recognized $1.0 million of DSU expense in general and administrative expense and contributed surplus (December 31, 2021: $0.5 million).

The following table details the PSU and DSU activity:

	Performance Share Units	Deferred Share Units
Balance at January 1, 2021	23,516,984	2,301,599
Additions	10,030,262	660,940
Issued/forfeiture	(9,963,924)	—
Balance at December 31, 2021	23,583,322	2,962,539
Additions	5,165,917	1,073,483
Issued/forfeiture	(9,022,071)	—
Exercised/settled	—	(1,384,268)
Balance at December 31, 2022	19,727,168	2,651,754

17. REVENUES NET OF ROYALTY

The Company's oil revenue is determined pursuant to the terms of various sales agreements. The transaction price for crude is based on the commodity price in the production month, adjusted for quality, allowable deductions and other factors. Commodity prices are based on market indices.

	Twelve months ended	
	December 31 2022	**December 31 2021**
Sales		
Oil revenue	359,106	159,189
Royalty	(25,713)	(8,962)
Social fund (see Note 4)	(6,278)	—
Net revenue	327,115	150,227

18. GENERAL AND ADMINISTRATIVE EXPENSES

	Twelve months ended	
	December 31 2022	**December 31 2021**
Salaries and benefits	10,994	9,387
Legal, audit and consulting fees	4,830	3,051
Community support	2,372	1,451
Office rent and administrative	2,870	1,678
Share- based compensation	4,089	2,548
Costs directly attributable to PP&E and operating expenses	(5,264)	(3,833)
Total	19,891	14,282

The Company's general and administrative expenses were $5.6 million higher in 2022 compared to 2021, due to an increase in salaries and headcount, higher professional fees and Environmental, Social, and Governance ("ESG") consulting expenses and an increase in share-based compensation, partially offset by costs directly attributable to PP&E and operating expenses.

19. OTHER EXPENSES

	Twelve months ended	
	December 31 2022	December 31 2021
Other expenses	978	—
Total	978	—

In Q3 2022, PetroTal incurred $1.0 million related to erosion control costs in the Ucayali River which runs next to the Bretana field.

20. FINANCE EXPENSE

	Twelve months ended	
	December 31 2022	December 31 2021
Bond interest and fees amortization	14,545	13,313
Other interest	2,540	1,338
Factoring costs	1,417	2,668
Lease interest	2,884	721
Accretion of decommissioning obligations	897	530
Interest income	(2,114)	(732)
Total	20,169	17,838

The Company's finance expenses were $2.3 million higher in 2022 compared to 2021, mainly due to the financial revaluation of the Ferrenergy lease in Q2 2022.

21. RELATED PARTY TRANSACTIONS

The Company had no related party transactions or off-balance sheet arrangements. The Company's key management includes the Directors and Officers.

	Twelve months ended	
	December 31 2022	December 31 2021
Salaries, incentives and short term benefits	1,785	1,505
Director's fees	1,050	369
Share-based compensation	1,615	968
Total	4,450	2,842

22. CAPITAL STRUCTURE

The Company's objective when managing capital is to ensure it has sufficient funds to maintain ongoing operations, to pursue the acquisition of oil and gas properties, and to maintain a flexible capital structure that optimizes the cost of capital at an acceptable risk. The Company manages its capital structure, which may include equity and debt, and adjusts it according to the funds available to support the exploration and development of its interests in its existing oil and gas properties, and to pursue other opportunities as they arise.

The Company defines its capital as follows:

	December 31 2022	December 31 2021
Equity	399,331	204,257
Working capital (current assets less current liabilities)	(139,771)	(47,319)
Total	259,560	156,938

23. TAXES

The Company utilizes the liability method of accounting for income taxes. Under the liability method, deferred tax assets and liabilities are recognized using current tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities.

Deferred tax assets are reduced by a valuation allowance if some portion or all of the net deferred tax assets will not be realized. The Company's ability to realize deferred tax assets is assessed throughout the year and a valuation allowance is established, if required. The Company also routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts, including interest where appropriate. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on technical merits.

The Company's effective tax rate is impacted each quarter by the relative pre-tax income (loss) earned by the Company's operations in Canada, U.S., and Peru. The Company is subject to statutory tax rates of 23% in Canada, 21% in the U.S., and 32% in Peru. 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:

	December 31, 2022	December 31, 2021
Earnings before income taxes	205,917	63,968
Canadian corporate tax rate	23.00 %	23.00 %
Expected income tax expense	47,361	14,713
Increase (decrease) in taxes resulting from:		
Non-deductible expenses and other	1,661	5,984
Tax differential on foreign jurisdictions	18,384	6,223
Recognition of NOL's not previously recognized	(50,031)	(25,968)
Prior year true up and change in tax rates	15	(956)
Provision for income taxes	**17,390**	**(4)**
Current tax expense	501	—
Deferred tax expense (recovery)	16,889	(4)

The following table reconciles the Company's deferred tax asset and liability:

	December 31, 2022	December 31, 2021
Deferred tax assets:		
Finance leases	10	—
Accrued bonus	254	220
Property and equipment	(21)	—
Non-capital losses	855	409
Deferred tax assets	**1,098**	**629**
Deferred tax liabilities:		
Intangibles	1,751	—
Accruals-US	—	(40)
Pre-operation	3,186	—
ROU asset	6,032	—
Asset retirement obligation	4,286	—
Property and equipment	(57,204)	—
Net operating loss carryover-Peru	29,985	—
Temps-other assets	821	—
Temps-other liabilities	(600)	—
Derivatives	(5,643)	—
Deferred tax liabilities	**(17,386)**	**(40)**

The Company recognized the net tax amount related to Net Operating Losses ("NOLs") and deferred tax liabilities in Peru. As at the tax year ended December 31, 2022, the accumulated Peruvian tax losses of $112 million mainly related to Block 95. Also, the Canadian non-capital losses can be carried forward for twenty years for a total of $69 million (the majority is subject to a valuation allowance) in losses, and $1.7 million for US losses. There is generally no carryback period, and the carryover period starts with the taxable year following the loss and continues indefinitely**.** The deferred tax amount not recognized during 2022 was $16 million, compared to $51.9 million in 2021. The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as of December 31, 2022 is approximately $49.6 million, compared to nil in 2021.

The tax rate of the license contracts is 32%; however, due to accumulated tax losses, the Company initially pays an installment of 2% tax on revenue, which is recoverable against any future tax payable (see Note 8).

24. COMMITMENTS

As at December 31, 2022, 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	December 2023
107	Perupetro S.A.	$1,500	2nd exploration well, minimum work 5th exploratory period	December 2023
		$3,000		

25. SUBSEQUENT EVENTS

On March 2, 2023, the Company was informed that the Supreme Decree was signed by Peru's President authorizing Perupetro to execute the amendment incorporating the 2.5% social trust fund into the Block 95 license contract. The social trust now requires its bylaws to be approved by the working table participants which is estimated to occur in April 2023.

On March 2, 2023, Banco de Credito del Peru finalized a $20 million unsecured revolving loan with an interest rate of 8.97%. The initial term of the loan is two months with the option to renew.

On March 24, 2023, the Company elected to repay the remaining $55 million bond principal, plus interest and fees. The original bond maturity was February 2024.