Petrus Resources

ANNUAL REPORT

December 31, 2023

Petrus Resources Ltd. ("Petrus" or the "Company") (TSX: PRQ) is pleased to report financial and operating results as at and for the three and twelve months ended December 31, 2023 and to provide 2023 year end reserves information as evaluated by Insite Petroleum Consultants Ltd. ("Insite"). The Company's Management's Discussion and Analysis ("MD&A") and audited consolidated financial statements are available on SEDAR+ (the System for Electronic Document Analysis and Retrieval) at www.sedarplus.ca.

Q4 2023 HIGHLIGHTS

- **Dividends** – The Company declared a regular monthly dividend of $0.01 per share, starting January 2024, following its inaugural special dividend of $0.03 per share which was paid on November 9, 2023. These dividends serve as a tangible reward allowing Petrus' shareholders to realize the value created by the Company's continued success.

- **Increased production** – Total production increased by 4% to 9,474 boe/d(1) in the fourth quarter of 2023, compared to 9,113 boe/d in the fourth quarter of 2022.

- **Lower operating expense** – Operating expense in the fourth quarter of 2023 was $5.07/boe, a 26% decrease from $6.86/boe in the fourth quarter of 2022. The decrease is primarily due to the realization of the cost recovery on Petrus' North Ferrier gas plant interest.

- **Infrastructure investment** – Construction of the North Ferrier pipeline was completed in the fourth quarter of 2023 and production started flowing to our Ferrier gas plant near the end of the quarter. This strategic infrastructure allows Petrus to expedite the development of its North Ferrier assets while providing the same low cost structure as its core Ferrier area.

- **Commodity price decline** – Total realized price of $30.60/boe decreased by 47% in the fourth quarter of 2023 compared to the fourth quarter of 2022 ($57.81/boe) as a result of lower commodity prices across all products.

- **Funds flow(2)** – The Company generated funds flow(2) of $16.5 million in the fourth quarter of 2023, a 52% decline from the fourth quarter of 2022 due to lower commodity prices.

2023 ANNUAL HIGHLIGHTS

- **Increased production** – Total average annual production increased by 35% to 10,301 boe/d in 2023, compared to 7,604 boe/d in 2022, in line with Petrus' 2023 production guidance.

- **Commodity price decline** – Total realized price of $33.31/boe decreased by 39% in 2023 compared to 2022 ($54.63/boe) as a result of lower commodity prices across all products.

- **Funds flow(2)** – Petrus generated funds flow of $78.0 million, only 11% lower than the prior year despite a 39% lower total realized price per boe in 2023 and also within Petrus' 2023 guidance. The decrease in 2023 funds flow was due to lower commodity prices, which was partially offset by higher production volumes and the realized gain on financial derivatives.

- **Net debt(2)** – Net debt was $62.6 million at December 31, 2023 or 0.8x funds flow for 2023. The Company targets a net debt to funds flow ratio of less than 1.0x.

2024 OUTLOOK(3)

Petrus' 2024 budget was announced in February and prioritizes its commitment to generating sustainable returns and maintaining a healthy balance sheet. To date, Petrus has successfully completed its planned first quarter 2024 drilling program, and the wells are scheduled to be completed and put on production over the next few months.

The 2024 capital budget targets(4):

- Capital spending of $40 million to $50 million - 90% allocated toward drilling new wells in Ferrier and North Ferrier areas
- Annual average production of 9,000 to 10,000 boe per day(1)
- Annual funds flow(2) of $55 million to $65 million
- Free funds flow(2) of $15 million to $20 million
- Monthly dividend of $0.01/share - annually this represents approximately 9% of the current share price
- Net debt(1) in the range of $55 million to $60 million

The Company remains optimistic on the long-term outlook for commodity prices and is strategically positioned to take full advantage of the next constructive pricing cycle. As always, Petrus will closely monitor changing market conditions and is ready to adjust its capital program accordingly, guided by its commitment to delivering sustainable returns to shareholders, which remains the foundation of the Company's long-term strategy.

(1)Disclosure of production on a per boe basis consists of the constituent product types and their respective quantities. Refer to "BOE Presentation" and "Production and Product Type Information" for further details.
(2)Non-GAAP measure or non-GAAP ratio. Refer to "Non-GAAP and Other Financial Measures" in the Management's Discussion & Analysis attached hereto.
(3)Refer to "Advisories - Forward-Looking Statements" in the Management's Discussion & Analysis attached hereto.
(4)The budget was established using an average price forecast of US$75/bbl WTI for oil, an AECO gas price of CAD$2.50/GJ and a foreign exchange rate of US$0.74.

PRESIDENT'S MESSAGE

This past year provided another poignant example of the volatile nature of this business and the need to be disciplined, flexible, and low-cost. Prices declined dramatically from the post-COVID and Ukraine war induced highs of 2022. Despite all the talk about returning capital to shareholders, most of the increased cash flow in 2022 was directed towards drilling, and record production levels were quickly reached in both Canada and the US. Combine that with the abnormally warm winter and you get the low natural gas prices we see currently. Here at Petrus, we take pride in being nimble and flexible. We suspended drilling in March and re-evaluated our capital program, eventually cutting drilling capital in half and re-deploying remaining capital to some strategic targets. Few in our business cut as quickly or deeply, but in hindsight it was absolutely the correct decision. The re-directed capital was used to position us for future growth, building a pipeline to connect our North Ferrier assets to our Ferrier gas plant and drilling some strategic wells that tied into that pipeline.

The declining commodity prices once again brought into focus the importance of being a low-cost producer and of limiting the use of debt. With its operated infrastructure, Petrus has a cost structure more equivalent to much larger producers, allowing us to continue to generate good cash flow even in low price environments. And, as anyone who has followed us over the last couple years will be well aware, Petrus has worked hard to reduce debt and its associated risk.

Petrus' exceptional growth over the last couple years, coupled with sustainable cash flow generation positioned us to take the next step in our journey and initiate dividend payments to our shareholders in 2023. We first paid a special dividend in Q4, and then declared a regular monthly dividend starting in January 2024. It has always been our goal to provide a tangible return to our shareholders, and that we were able to achieve this goal in the midst of this low-price environment is a testament to the strength of our business.

As we embark on the year ahead, we are optimistic about Petrus' future prospects. Current natural gas prices are no doubt challenging, but the company is in a much better position now than it was the last time prices were this low. With a stronger financial position, the ability to pay dividends, a keen eye for opportunities, and a proven team that can make things happen Petrus is well positioned to take advantage of the bright future ahead for this industry.
Thanks again for your support.

Ken Gray
President, Chief Executive Officer and Director

RESERVES

Petrus' 2023 year end reserves were evaluated by the independent reserves evaluator InSite Petroleum Consultants Ltd. ("Insite") in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") as of December 31, 2023 ("2023 Insite Report"). Additional reserve information as required under NI 51-101 will be included in our Annual Information Form for the year ended December 31, 2023, which will be available under the Company's profile on SEDAR+ (the System for Electronic Document Analysis and Retrieval) at www.sedarplus.ca.

Petrus has a reserves committee, comprised of a majority of independent board members, that reviews the qualifications and appointment of the independent reserves evaluator. The committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the independent qualified reserve evaluator conducted in accordance with the COGE Handbook and NI 51-101. The evaluations are conducted using all available geological and engineering data. The reserves committee has reviewed the reserves information and approved the 2023 Insite Report.

The following table provides a summary of the Company's before tax reserves as evaluated by Insite:

As at December 31, 2023	**Total Company Interest [(1)(3)]**							
Reserve Category	**Conventional Natural Gas (mmcf)**	**Light and Medium Crude Oil (mbbl)**	**Condensate NGL (mmbl)**	**Other NGL (mbbl)**	**Total (mboe)**	**NPV 0%[(2)] ($000s)**	**NPV 5%[(2)] ($000s)**	**NPV 10%[(2)] ($000s)**
Proved Developed Producing	76,176	786	2,687	2,199	18,368	350,754	273,749	226,577
Proved Developed Non-Producing	1,516	7	37	38	334	4,244	3,162	2,433
Proved Undeveloped	121,139	3,027	2,966	3,396	29,579	426,193	273,193	179,434
Total Proved	**198,831**	**3,820**	**5,690**	**5,632**	**48,281**	**781,190**	**550,105**	**408,445**
Proved + Probable Producing	92,978	931	3,332	2,710	22,469	457,213	333,717	266,914
Total Probable	**109,300**	**3,062**	**2,500**	**3,308**	**27,086**	**510,098**	**291,076**	**185,544**
Total Proved Plus Probable	**308,131**	**6,882**	**8,190**	**8,940**	**75,367**	**1,291,289**	**841,181**	**593,989**

(1)Tables may not add due to rounding.
(2)NPV 0%, NPV 5% and NPV 10% refer to the risked net present value of the future net revenue of the Company's reserves, discounted by 0%, 5% and 10%, respectively and is presented before tax and based on Insite's pricing assumptions.
(3)Total company interest reserve volumes presented above and in the remainder of this Annual Report are presented as the Company's total working interest before the deduction of royalties (but after including any royalty interests of Petrus).

In 2023, Petrus' development program generated proved developed producing ("PDP") reserve volume additions of 4.4 mmboe. The Company produced 3.8 mmboe and divested of 0.1 mmboe of PDP reserves resulting in a net increase of 0.6 mmboe to end the year with 18.4 mmboe of PDP reserves (31% crude oil and liquids).

At December 31, 2023, Petrus' PDP, Total Proved ("TP"), and Proved plus Probable ("P+P") reserves were valued at $226.6 million, $408.4 million and $594.0 million, respectively, before-tax, discounted at 10%, based on the 2023 Insite Report. In 2023, the Company realized Finding, Development and Acquisition ("FD&A") costs of $19.67/boe for PDP reserves.

Based on the 2023 Insite Report, the Company's PDP reserve value before-tax, discounted at 10% is $1.68 per share (134,501,972 fully-diluted common shares outstanding at December 31, 2023). On the same basis, the P+P reserve value before-tax, discounted at 10%, is $4.42 per share.

FUTURE DEVELOPMENT COST

Future Development Cost ("FDC") reflects Insite's best estimate of what it will cost to bring the P+P undeveloped reserves on production. The following table provides a summary of the Company's FDC as set forth in the 2023 Insite Report:

Future Development Cost ($000s)	**Total Proved**	**Total Proved + Probable**
2024	90,209	96,328
2025	111,299	132,962
2026	129,859	154,841
2027	59,691	120,446
2028	—	113,860
Total FDC, Undiscounted	**391,058**	**618,437**
Total FDC, Discounted at 10%	**328,247**	**490,116**

PERFORMANCE RATIOS

The following table highlights annual performance ratios for the Company from 2019 to 2023[3]:

	December 31, 2023	**December 31, 2022**	**December 31, 2021**	**December 31, 2020**	**December 31, 2019**
Proved Producing					
FD&A ($/boe) [1][2]	**19.67**	12.58	15.64	4.83	13.31
F&D ($/boe) [1][2]	**19.67**	12.70	8.90	4.83	12.81
Reserve Life Index (yr) [1]	**5.27**	5.31	5.41	5.20	3.80
Reserve Replacement Ratio [1]	**1.15**	3.20	0.78	1.20	0.40
FD&A Recycle Ratio [1]	**1.06**	2.91	1.58	2.60	1.20
Proved Developed					
FD&A ($/boe) [1][2]	**19.34**	12.50	14.54	4.71	12.49
F&D ($/boe) [1][2]	**19.34**	12.61	8.53	4.71	12.03
Reserve Life Index (yr) [1]	**5.36**	5.39	5.50	5.20	4.80
Reserve Replacement Ratio [1]	**1.17**	3.22	0.84	1.20	0.50
FD&A Recycle Ratio [1]	**1.08**	2.93	1.70	2.70	1.30
Total Proved					
FD&A ($/boe) [1][2]	**14.50**	18.24	10.51	1.29	1.09
F&D ($/boe) [1][2]	**14.50**	33.99	9.24	1.29	(6.83)
Reserve Life Index (yr) [1]	**13.85**	12.18	15.30	10.90	9.90
Reserve Replacement Ratio [1]	**2.98**	3.79	4.50	(1.00)	0.30
FD&A Recycle Ratio [1]	**1.44**	2.01	2.35	9.80	14.40
Future Development Cost (undiscounted) ($000s)	**391,058**	313,786	233,684	156,815	174,027
Total Proved + Probable					
FD&A ($/boe) [1][2]	**14.00**	15.66	10.57	0.37	(7.32)
F&D ($/boe) [1][2]	**14.00**	36.12	8.36	0.37	190.21
Reserve Life Index (yr) [1]	**21.62**	19.68	23.29	17.70	15.40
Reserve Replacement Ratio [1]	**3.49**	6.63	5.10	(1.30)	—
FD&A Recycle Ratio [1]	**1.50**	2.34	2.33	33.70	(2.10)
Future Development Cost (undiscounted) ($000s)	**618,437**	519,823	343,489	252,335	267,652

[1] *Refer to "Oil and Gas Disclosures" in the Management's Discussion & Analysis attached hereto.*

[2] *Certain changes in FD&A costs and F&D costs produce non-meaningful figures as discussed in "Oil and Gas Disclosures" in the Management's Discussion & Analysis attached hereto.*

While FD&A costs and F&D costs, reserve life index, reserve replacement ratio and FD&A recycle ratio are commonly used in the oil and nature gas industry and have been prepared by management, 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.

NET ASSET VALUE

The Company estimates its net asset value to be $562.0 million or $4.18 per full diluted common share as at December 31, 2023 based on the present value of its P+P reserves before tax, discounted at 10%. The components of the Company's net asset value are set forth in the table below. The reader is cautioned that these amounts may not be directly comparable to other companies, as the term "Net Asset Value" does not have a standardized meaning under GAAP or NI 51-101. Management believes that net asset value provides a useful measure to analyze the comparative change in the Company's estimated value on a normalized basis.

The following table shows the Company's Net Asset Value ("NAV"), calculated using the 2023 Insite Report and Insite's December 31, 2023 price forecast:

As at December 31, 2023 ($000s except per share)	Proved Developed Producing	Total Proved	Proved + Probable
Present Value Reserves, before tax (discounted at 10%) [(1)]	226,577	408,445	593,989
Undeveloped Land Value [(2)]	30,628	30,628	30,628
Net Debt [(3)]	(62,596)	(62,596)	(62,596)
Net Asset Value	**194,609**	**376,477**	**562,021**
Fully Diluted Shares Outstanding	134,542	134,542	134,542
Estimated Net Asset Value per Fully Diluted Share	**$1.45**	**$2.80**	**$4.18**

[(1)]Based on the 2023 Insite Report, using the forecast future prices and costs.
[(2)]Based on the exploration and evaluation assets as per the Company's December 31, 2023 audited consolidated financial statements.
[(3)]Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" in the Management's Discussion & Analysis attached hereto.

Petrus Resources

MANAGEMENT'S DISCUSSION & ANALYSIS

December 31, 2023

MANAGEMENT'S DISCUSSION & ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of the financial and operating results of Petrus Resources Ltd. ("Petrus" or the "Company") as at and for the year ended December 31, 2023. This MD&A is dated March 25, 2024 and should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2023 and 2022. The Company's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are directed to the "Advisories" section at the end of this MD&A regarding forward-looking statements and boe presentation and to the section "Non-GAAP and Other Financial Measures" herein.

The principal undertaking of Petrus is the investment in energy assets. The operations of the Company consist of the acquisition, development, exploration and exploitation of these assets. The Company's head office is located at 2400, 240 - 4th Avenue SW, Calgary, Alberta, Canada. Additional information on Petrus, including the most recently filed Annual Information Form ("AIF"), are available under the Company's profile on SEDAR+ (the System for Electronic Document Analysis and Retrieval) at www.sedarplus.ca.

SELECTED FINANCIAL INFORMATION

OPERATIONS	Twelve months ended Dec. 31, 2023	Twelve months ended Dec. 31, 2022	Three months ended Dec. 31, 2023	Three months ended Sept. 30, 2023	Three months ended Jun. 30, 2023	Three months ended Mar. 31, 2023
Average production						
Natural gas (mcf/d)	42,779	30,441	39,891	42,045	44,010	45,237
Oil (bbl/d)	1,595	1,436	1,218	1,316	1,670	2,192
NGLs (bbl/d)	1,575	1,094	1,607	1,556	1,486	1,654
Total (boe/d)	**10,301**	**7,604**	**9,474**	**9,880**	**10,492**	**11,385**
Total (boe)	**3,760,004**	**2,775,561**	**871,567**	**908,985**	**954,738**	**1,024,645**
Total liquids weighting	31 %	33 %	30 %	29 %	30 %	34 %
Realized Prices						
Natural gas ($/mcf)	3.01	6.03	2.76	2.81	2.64	3.78
Oil ($/bbl)	95.61	113.19	98.63	99.33	91.69	94.63
NGLs ($/bbl)	39.31	63.26	37.26	37.09	34.82	47.55
Total realized price ($/boe)	**33.31**	**54.63**	**30.60**	**31.05**	**30.59**	**40.16**
Royalty income	0.09	0.26	0.09	0.06	0.06	0.16
Royalty expense	(4.59)	(8.70)	(4.78)	(3.37)	(3.66)	(6.38)
Gain (loss) on risk management activities	0.40	(2.17)	—	—	0.03	1.45
Net oil and natural gas revenue ($/boe)	**29.21**	**44.02**	**25.91**	**27.74**	**27.02**	**35.39**
Operating expense	(6.25)	(7.45)	(5.07)	(6.70)	(5.83)	(7.26)
Transportation expense	(1.63)	(2.08)	(1.46)	(1.54)	(1.40)	(2.05)
Operating netback[1] ($/boe)	**21.33**	**34.49**	**19.38**	**19.50**	**19.79**	**26.08**
Realized gain (loss) on financial derivatives ($/boe)	2.14	(0.58)	1.99	1.21	3.56	1.77
Cash other income	0.02	0.10	(0.18)	0.04	0.04	0.16
General & administrative expense	(1.11)	(1.22)	(0.37)	(1.27)	(1.55)	(1.20)
Cash finance expense	(1.28)	(1.14)	(1.43)	(1.26)	(1.33)	(1.11)
Decommissioning expenditures	(0.37)	(0.05)	(0.43)	(0.34)	(0.58)	(0.13)
Funds flow & corporate netback[1] ($/boe)	**20.73**	**31.60**	**18.96**	**17.88**	**19.93**	**25.57**

FINANCIAL (000s except $ per share)	Twelve months ended Dec. 31, 2023	Twelve months ended Dec. 31, 2022	Three months ended Dec. 31, 2023	Three months ended Sept. 30, 2023	Three months ended Jun. 30, 2023	Three months ended Mar. 31, 2023
Oil and natural gas revenue	125,605	152,350	26,747	28,273	29,266	41,319
Net income (loss)	50,731	60,868	39,708	(11,293)	5,043	17,273
Net income (loss) per share						
Basic	0.41	0.53	0.32	(0.09)	0.04	0.14
Fully diluted	0.40	0.51	0.32	(0.09)	0.04	0.14
Funds flow[1]	78,024	87,716	16,525	16,243	19,040	26,216
Funds flow per share [1]						
Basic	0.63	0.76	0.13	0.13	0.15	0.21
Fully diluted	0.62	0.73	0.13	0.13	0.15	0.21
Capital expenditures	86,843	96,744	32,029	21,617	3,380	29,820
Weighted average shares outstanding						
Basic	123,469	115,189	123,812	123,743	123,752	123,416
Fully diluted	126,436	119,525	124,840	123,743	127,040	127,358
As at period end						
Common shares outstanding						
Basic	124,266	123,239	124,266	123,867	123,849	123,239
Fully diluted	134,542	133,377	134,542	134,436	134,423	133,377
Total assets	437,842	381,057	437,842	380,100	383,231	403,276
Non-current liabilities	60,926	63,021	60,926	59,687	62,630	68,056
Net debt[1]	62,596	50,808	62,596	42,610	36,857	53,111

[1] Non-GAAP financial measure or non-GAAP ratio. Refer to "Non-GAAP and Other Financial Measures".
[2] Disclosure of production on a per boe basis consists of the constituent product types and their respective quantities. Refer to "BOE Presentation" for further details.

OPERATIONS UPDATE

Fourth quarter average production by area was as follows:

For the three months ended December 31, 2023	Ferrier	North Ferrier	Foothills	Central Alberta	Kakwa	Total
Natural gas (mcf/d)	30,836	2,558	1,735	4,634	129	39,892
Oil (bbl/d)	808	85	83	233	10	1,219
NGLs (bbl/d)	1,393	61	6	138	9	1,607
Total (boe/d)	**7,340**	**572**	**378**	**1,144**	**40**	**9,474**

Fourth quarter 2023 production averaged 9,474 boe/d compared to 9,113 boe/d in the fourth quarter of 2022. Production has increased as a result of the Company's capital program that was executed in 2023. Two gross (2.0 net) wells were drilled during the fourth quarter of 2023. Completion activities of these wells is set to commence in late spring of 2024.

CAPITAL EXPENDITURES

The Company's 2023 capital program continued into the fourth quarter with capital expenditures (excluding acquisitions and dispositions) totaling $32.0 million, compared to $37.8 million in the prior year comparative period.

Capital expenditures (excluding acquisitions and dispositions) totaled $86.8 million in the year ended December 31, 2023, compared to $96.7 million in 2022. The Company successfully executed its 2023 capital program including the completion of its North Ferrier to Ferrier pipeline. Capital expenditures for the year were higher than the revised 2023 budget guidance mainly due to additional infrastructure spending, the prepurchase of drilling and completion materials to be used for future wells, and higher net drill and complete costs than budgeted as the Company gained certain partner interests.

The following table shows capital expenditures for the reporting periods indicated, excluding acquisitions and dispositions. All capital is presented before decommissioning obligations.

Capital Expenditures ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Drill and complete	**16,910**	32,073	**58,678**	81,953
Oil and gas equipment and facilities	**14,470**	4,921	**25,747**	11,853
Geological	**—**	—	**545**	—
Land and lease	**411**	291	**628**	1,759
Office	**—**	—	**109**	
Capitalized general and administrative expense	**238**	507	**1,136**	1,179
Total capital expenditures	**32,029**	**37,792**	**86,843**	**96,744**
Gross (net) wells drilled	**2 (2.0)**	**5 (4.6)**	**15 (12.4)**	**20 (14.8)**

During the first quarter of 2022, Petrus closed an acquisition in its core Ferrier area. Included in this acquisition was approximately 425 boe/d of production and 5,120 net acres of undeveloped land. The acquisition was made for total share consideration of 10 million shares ($15.2 million).

RESULTS OF OPERATIONS

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Twelve months ended Dec. 31, 2023	Twelve months ended Dec. 31, 2022	Three months ended Dec. 31, 2023	Three months ended Sept. 30, 2023	Three months ended Jun. 30, 2023	Three months ended Mar. 31, 2023
Average production						
Natural gas (mcf/d)	42,779	30,441	39,891	42,045	44,010	45,237
Oil (bbl/d)	1,595	1,436	1,218	1,316	1,670	2,192
NGLs (bbl/d)	1,575	1,094	1,607	1,556	1,486	1,654
Total (boe/d)	**10,301**	**7,604**	**9,474**	**9,880**	**10,492**	**11,385**
Total (boe)	**3,760,004**	**2,775,561**	**871,567**	**908,985**	**954,738**	**1,024,645**
Sales ($000s)						
Natural gas	46,972	67,025	10,114	10,882	10,569	15,407
Oil	55,676	59,348	11,049	12,031	13,930	18,666
NGLs	22,603	25,267	5,508	5,308	4,710	7,077
Royalty revenue	354	710	76	52	57	169
Oil and natural gas sales	**125,605**	**152,350**	**26,747**	**28,273**	**29,266**	**41,319**
Average realized prices						
Natural gas ($/mcf)	3.01	6.03	2.76	2.81	2.64	3.78
Oil ($/bbl)	95.61	113.19	98.63	99.33	91.69	94.63
NGLs ($/bbl)	39.31	63.26	37.26	37.09	34.82	47.55
Total realized price ($/boe)	**33.31**	**54.63**	**30.60**	**31.05**	**30.59**	**40.16**
Hedging gain (loss) ($/boe)	2.14	(0.58)	1.99	1.21	3.56	1.77
Gain (loss) on risk management ($/boe)	0.40	(2.17)	—	—	0.03	1.45
Total price including hedging ($/boe)	**35.85**	**51.88**	**32.59**	**32.26**	**34.18**	**43.38**

Average benchmark prices	Twelve months ended Dec. 31, 2023	Twelve months ended Dec. 31, 2022	Three months ended Dec. 31, 2023	Three months ended Sept. 30, 2023	Three months ended Jun. 30, 2023	Three months ended Mar. 31, 2023
Natural gas						
AECO 5A (C$/GJ)	2.51	5.04	2.18	2.46	2.32	3.05
AECO 7A (C$/GJ)	2.78	5.22	2.52	2.26	2.22	4.12
Crude oil						
Mixed Sweet Blend Edm (C$/bbl)	99.75	119.41	96.60	107.47	95.07	99.87
WTI (US$/bbl)	77.63	94.23	78.39	82.26	73.78	76.13
Foreign exchange						
US$/C$	0.73	0.74	0.73	0.74	0.74	0.74

FUNDS FLOW AND NET INCOME

Petrus generated funds flow of $16.5 million in the fourth quarter of 2023 compared to $34.1 million in the fourth quarter of 2022. The 52% decrease is due to lower commodity prices despite 4% higher production. The Company's total realized price was $30.60/boe in the fourth quarter of 2023 compared to $57.81/boe in the prior year comparative period.

For the year ended December 31, 2023, Petrus generated funds flow of $78.0 million compared to $87.7 million in the prior year. The 11% decrease is due to lower commodity prices partially offset by higher production.

Petrus reported net income of $39.7 million in the fourth quarter of 2023, compared to net income of $22.1 million in the fourth quarter of 2022. The 80% increase is primarily due to the realization of deferred tax assets, higher production, lower operating costs, higher other income and an increase in hedging gains (realized and unrealized) and was partially offset by lower commodity prices.

The Company generated net income of $50.7 million for the year ended December 31, 2023 compared to net income of $60.9 million for the year ended December 31, 2022. The year over year change is mainly due to the decline in commodity prices.

($000s except per share)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Funds flow	**16,525**	**34,117**	**78,024**	**87,716**
Funds flow per share - basic	0.13	0.28	0.63	0.76
Funds flow per share - fully diluted	0.13	0.27	0.62	0.73
Net income	39,708	22,097	50,731	60,868
Net income per share - basic	0.32	0.18	0.41	0.53
Net income per share - fully diluted	0.32	0.17	0.40	0.51
Common shares outstanding (000s)				
Basic	124,266	123,239	124,266	123,239
Fully diluted	134,542	133,377	134,542	133,377
Weighted average shares outstanding (000s)				
Basic	123,812	122,545	123,469	115,189
Fully diluted	124,840	127,600	126,436	119,525

OIL AND NATURAL GAS SALES

Fourth quarter average production in 2023 was 9,474 boe/d (70% natural gas), 4% higher than the fourth quarter of 2022 (9,113 boe/d; 61% natural gas). Fourth quarter oil and natural gas sales in 2023 was $26.7 million compared to $48.6 million in 2022. The 45% decrease is due to the decline in commodity prices.

Average production for the year ended December 31, 2023 was 10,301 boe/d (69% natural gas), 35% higher than 2022 (7,604 boe/d; 67% natural gas). Total oil and natural gas revenue decreased from $152.4 million in 2022 to $125.6 million in 2023 due to lower commodity prices.

The following table presents oil and natural gas revenue by product and the change from the prior comparative periods:

Oil and Natural Gas Sales ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	% Change	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022	% Change
Natural gas	**10,114**	18,434	(45)%	**46,972**	67,025	(30)%
Crude oil and condensate	**11,049**	24,163	(54)%	**55,676**	59,348	(6)%
Natural gas liquids	**5,508**	5,869	(6)%	**22,603**	25,267	(11)%
Royalty income	**76**	124	(39)%	**354**	710	(50)%
Total oil and natural gas sales	**26,747**	**48,590**	**(45)%**	**125,605**	**152,350**	**(18)%**

The following table provides the average benchmark commodity prices and the Company's average realized commodity prices (before hedging and risk management gains/losses):

	Three months ended December 31, 2023	Three months ended December 31, 2022	% Change	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022	% Change
Average benchmark prices						
Natural gas						
AECO 5A (C$/GJ)	**2.18**	4.85	(55)%	**2.51**	5.04	(50)%
AECO 7A (C$/GJ)	**2.52**	5.29	(52)%	**2.78**	5.22	(47)%
Crude oil						
Mixed Sweet Blend Edm (C$/bbl)	**96.60**	108.14	(11)%	**99.75**	119.41	(16)%
Average realized prices						
Natural gas ($/mcf)	**2.76**	6.04	(54)%	**3.01**	6.03	(50)%
Oil ($/bbl)	**98.63**	106.85	(8)%	**95.61**	113.19	(16)%
NGLs ($/bbl)	**37.26**	56.90	(35)%	**39.31**	63.26	(38)%
Total average realized price	**30.60**	**57.81**	**(47)%**	**33.31**	**54.63**	**(39)%**

The following table provides a breakdown of composition of the Company's production volume by product:

Production Volume by Product (%)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Natural gas	**70 %**	61 %	**69 %**	67 %
Crude oil and condensate	**13 %**	27 %	**16 %**	19 %
Natural gas liquids	**17 %**	12 %	**15 %**	14 %
Total commodity sales from production	**100 %**	**100 %**	**100 %**	**100 %**

Natural gas

Natural gas sales for the year ended December 31, 2023 were $47.0 million, which decreased 30% from the prior year ($67.0 million). The average realized natural gas price for the year ended December 31, 2023 decreased 50% to $3.01/mcf from the prior year ($6.03/mcf). Natural gas production of 42,779 mcf/d was up 41% over the prior year comparative production of 30,441 mcf/d. Natural gas sales accounted for 38% of oil and natural gas sales in 2023, compared to 44% in the prior year.

Fourth quarter 2023 natural gas sales were $10.1 million, which decreased 45% from the prior year comparative period ($18.4 million). The average realized natural gas price in the fourth quarter of 2023 was $2.76/mcf, compared to $6.04/mcf in the fourth quarter of 2022 (54% decrease). Natural gas production increased 20% from 33,201 mcf/d in the fourth quarter of 2022 to 39,891 mcf/d in the fourth quarter of 2023. Natural gas sales accounted for 38% of oil and natural gas sales in the fourth quarter of 2023 and the prior year comparative period.

Crude oil and condensate

Oil and condensate sales for the year ended December 31, 2023 were $55.7 million, which decreased 6% from the prior year ($59.3 million). The average realized oil and condensate price for the year ended December 31, 2023 decreased 16% to $95.61/bbl from the prior year ($113.19/bbl). Oil and condensate production increased from 1,436 bbl/d in 2022 to 1,595 bbl/d in 2023, an increase of 11%. Oil and condensate sales accounted for 44% of oil and natural gas sales in 2023, compared to 39% in the prior year.

Fourth quarter 2023 oil and condensate sales were $11.0 million, which decreased 54% from the prior year comparative period ($24.2 million). The average realized oil and condensate price was $98.63/bbl for the fourth quarter of 2023, compared to $106.85/bbl in the fourth quarter of 2022, a decrease of 8%. Oil and condensate production decreased from 2,458 bbl/d in the fourth quarter of 2022 to 1,218 bbl/d in the fourth quarter of 2023, a decrease of 50%. Oil and condensate sales accounted for 41% of oil and natural gas sales in the fourth quarter of 2023, compared to 50% in the prior year comparative period.

Natural gas liquids (NGLs)

NGL sales for the year ended December 31, 2023 were $22.6 million, which decreased 11% from the prior year ($25.3 million). The average realized NGL price for the year ended December 31, 2023 decreased 38% to $39.31/bbl from the prior year ($63.26/bbl). NGL production increased from 1,094 bbl/d in 2022 to 1,575 bbl/d in 2023, an increase of 44%. NGL sales accounted for 18% of oil and natural gas sales in 2023, compared to 17% in the prior year.

Fourth quarter 2023 NGL sales were $5.5 million, which decreased 6% from the prior year comparative period ($5.9 million). The average realized NGL price was $37.26/bbl for the fourth quarter of 2023, a decrease of 35% from the realized price of $56.90/bbl in the fourth quarter of 2022. NGL production increased from 1,121 bbl/d in the fourth quarter of 2022 to 1,607 bbl/d in the fourth quarter of 2023, an increase of 43%. NGL sales accounted for 21% of oil and natural gas sales in the fourth quarter of 2023, compared to 12% in the prior year comparative period.

The Company's NGL production mix consists of ethane, propane, butane and pentanes+. The pricing received for NGL production is based on annual contracts effective the first of April each year. The contract prices are based on the product mix, the fractionation process required and the demand for fractionation facilities.

ROYALTY EXPENSE

Royalties are paid to the Government of Alberta and to gross overriding royalty owners. The following table shows the Company's royalty expense (net of royalty allowances and incentives) for the periods shown:

Royalty Expense ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Crown	**2,507**	4,194	**10,132**	15,463
Percent of production revenue	**9 %**	9 %	**8 %**	10 %
Gross overriding	**1,660**	2,443	**7,123**	8,698
Total	**4,167**	**6,637**	**17,255**	**24,161**

Fourth quarter royalty expense decreased from $6.6 million in 2022 to $4.2 million in 2023. On a twelve month basis, total royalty expense (net of royalty allowances and incentives) decreased from $24.2 million in 2022 to $17.3 million in 2023. The decrease in royalties for the fourth quarter and the year ended December 31, 2023 is due to lower revenue (as a result of decreased commodity prices) and lower crown royalty rates.

Gross overriding royalties decreased from $2.4 million in the fourth quarter of 2022 to $1.7 million in the fourth quarter of 2023. Gross overriding royalties decreased from $8.7 million for the year ended December 31, 2022 to $7.1 million for the year ended December 31, 2023. The decrease for both periods is due to lower revenue (as a result of decreased commodity prices).

OTHER INCOME

During the year ended December 31, 2023 the Company recorded $1.3 million as other income ($0.1 million cash). This amount mainly relates to the recognition of $1.2 million in carbon credits the Company earned from installing emission reduction equipment.

RISK MANAGEMENT

The Company utilizes financial derivative contracts and physical commodity contracts to mitigate commodity price risk and provide stability and sustainability to the Company's economic returns, funds flow and capital development plan. Petrus' risk management program is governed by guidelines approved by its Board of Directors.

The impact of the contracts that were settled during the reporting periods are actual cash settlements and are recorded as realized hedging gains (losses) for financial derivatives and premium (loss) on risk management activities for physical commodity contracts. The unrealized gain (loss) is recorded to demonstrate the change in fair value of the outstanding financial derivative contracts during the financial reporting period for financial statement purposes. Petrus does not follow hedge accounting for any of its risk management contracts in place. Petrus considers all of its risk management contracts to be effective economic hedges of its underlying business transactions.

The table below shows the realized and unrealized gain or loss on financial derivative contracts for the periods shown:

Net Gain (Loss) on Financial Derivatives ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Realized hedging gain (loss)	**1,737**	2,421	**8,051**	(1,601)
Unrealized hedging gain (loss)	**15,233**	(1,959)	**4,938**	7,609
Net gain on derivatives	**16,970**	**462**	**12,989**	**6,008**

In the fourth quarter of 2023, the Company recognized a realized hedging gain of $1.7 million compared to $2.4 million in the fourth quarter of 2022. The realized gain in the fourth quarter of 2023 increased the Company's corporate netback by $1.99/boe, compared to an increase of $2.89/boe in 2022. The Company recognized a realized hedging gain of $8.1 million during the year ended December 31, 2023, in comparison to the $1.6 million loss realized in 2022. The realized gains recognized in the fourth quarter of 2023 and the year ended December 31, 2023, were due to lower commodity prices (relative to the respective contracts settled).

During the fourth quarter of 2023, the Company recognized an unrealized gain of $15.2 million compared to an unrealized loss of $2.0 million in the fourth quarter of 2022. The Company recognized an unrealized hedging gain of $4.9 million for the year ended December 31, 2023 compared to an unrealized gain of $7.6 million for the year ended December 31, 2022. The unrealized gains represent the change in the unrealized risk management net asset or liability position during the year ended December 31, 2023.

The table below shows the gain (loss) on risk management activities related to physical commodity contracts for the periods shown:

Net Gain (Loss) on Risk Management Activities ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Gain (loss) on physical commodity contracts	—	(1,056)	1,522	(6,029)
Net gain (loss) on risk management activities	**—**	**(1,056)**	**1,522**	**(6,029)**

During the fourth quarter of 2023, the Company recorded no gain or loss on risk management activities ($1.1 million or $1.26/boe loss during the fourth quarter of 2022). For the year ended December 31, 2023, the Company recorded a gain of $1.5 million or $0.40/boe ($6.0 million or $2.17/boe loss for the year ended December 31, 2022). The gain during the year ended December 31, 2023 is a result of higher contract prices in comparison to benchmark prices during the year. As of March 31, 2023, all physical commodity contracts had matured and settled and the Company does not anticipate entering any new physical commodity contracts going forward.

The Company's risk management contracts provide protection from significant changes in crude oil and natural gas commodity prices for 2024 and 2025. The Company endeavors to hedge approximately half of its forecasted production for up to 12 months forward, and approximately 10% to 25% of its forecasted production for 12 to 24 months forward. The Company's hedging strategy is intended to provide stability and sustainability to the Company's economic returns, funds flow and capital development plan. A summary of Petrus' risk management contracts as at December 31, 2023 is included in note 11 of the Company's consolidated financial statements as at and for the year ended December 31, 2023. The 19,500 GJ/day average of natural gas hedged for 2023 represented 52% of fourth quarter 2023 average natural gas production. The 1,900 bbl/day average of oil hedged for 2023 represented 67% of fourth quarter 2023 average oil and NGL production.

The following table summarizes the average and minimum and maximum cap and floor prices for the 2023 to 2024 oil and natural gas contracts outstanding as at the date of this report:

	2024					2025				
	Q1	Q2	Q3	Q4	Avg.[1]	Q1	Q2	Q3	Q4	Avg.[1]
Oil hedged (bbl/d)	2,100	1,800	1,200	1,200	**1,575**	1,000	800	400	300	**625**
Avg. WTI cap price ($C/bbl)	96.39	96.57	96.10	96.21	**96.35**	93.45	93.12	93.33	92.68	**93.23**
Avg. WTI floor price ($C/bbl)	96.39	96.57	96.10	96.21	**96.35**	93.45	93.12	93.33	92.68	**93.23**
Natural gas hedged (GJ/d)	20,000	15,000	15,000	13,667	**15,917**	13,000	10,000	10,000	6,667	**9,917**
Avg. AECO 7A cap price ($C/GJ)	4.14	2.80	2.80	3.36	**3.34**	3.64	3.14	3.14	3.63	**3.39**
Avg. AECO 7A floor price ($C/GJ)	4.14	2.77	2.77	3.30	**3.31**	3.56	3.00	3.00	3.48	**3.26**

[1] *The volumes and prices reported are the weighted average volumes and prices for the period.*

OPERATING EXPENSE

The following table shows the Company's operating expense for the reporting periods shown:

Operating Expense ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Fixed and variable operating expense	**3,263**	5,173	**19,833**	16,954
Processing, gathering and compression charges	**1,458**	878	**5,068**	4,853
Total gross operating expense	**4,721**	**6,051**	**24,901**	**21,807**
Overhead recoveries	**(302)**	(298)	**(1,396)**	(1,142)
Total net operating expense	**4,419**	**5,753**	**23,505**	**20,665**
Operating expense, net ($/boe)	**5.07**	**6.86**	**6.25**	**7.45**

For the three months ended December 31, 2023, net operating expense totaled $4.4 million, a 23% decrease from $5.8 million during the prior year comparative period. Total operating expense is lower for three months ended December 31, 2023 mainly due to the third party cost recovery from the jointly owned gas plant in North Ferrier. On a per boe basis, net operating expense was 26% lower at $5.07/boe in the fourth quarter of 2023 compared to $6.86/boe in 2022.

For the year ended December 31, 2023, net operating expense totaled $23.5 million, a 14% increase from the $20.7 million incurred in the prior year comparative period. The increase in total operating expense for the year ended December 31, 2023 is mainly due to higher production. On a per boe basis, net operating expense was 16% lower at $6.25/boe in 2023 compared to $7.45/boe in 2022.

TRANSPORTATION EXPENSE

The following table shows transportation expense paid in the reporting periods:

Transportation Expense ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Transportation expense	**1,271**	1,743	**6,115**	5,772
Transportation expense ($/boe)	**1.46**	2.08	**1.63**	2.08

Petrus pays commodity and demand charges for transporting its gas on pipeline systems. The Company also incurs trucking costs on the portion of its oil and natural gas liquids production that is not pipeline connected. For the three months ended December 31, 2023 transportation expense was $1.3 million or $1.46/boe compared to $1.7 million or $2.08/boe in the prior year comparative period. On a twelve month basis, transportation expense totaled $6.1 million, or $1.63/boe for 2023, which is 6% higher and 22% lower, respectively, than the $5.8 million (or $2.08/boe) of costs incurred in the prior year. The decrease in transportation expense on a per boe basis is due to lower fuel surcharge and trucking costs due to a decrease in fuel prices in comparison to the prior year.

GENERAL AND ADMINISTRATIVE EXPENSE

The following table illustrates the Company's general and administrative ("G&A") expense which is shown net of capitalized costs directly related to exploration and development activities:

General and Administrative Expense ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Personnel, consultants and directors	**1,360**	1,750	**4,012**	4,103
Administrative expenses	**569**	407	**2,046**	1,733
Regulatory and professional expenses	**200**	223	**1,079**	879
Gross general and administrative expenses	**2,129**	**2,380**	**7,137**	**6,715**
Capitalized general and administrative expenses	(391)	(507)	(1,136)	(1,179)
Overhead recoveries	(1,418)	(947)	(1,818)	(2,147)
General and administrative expenses	**320**	**926**	**4,183**	**3,389**
General and administrative expense ($/boe)	**0.37**	**1.10**	**1.11**	**1.22**

G&A expense (net of capitalized G&A expense and overhead recoveries) for the fourth quarter of 2023 totaled $0.3 million or $0.37/boe, compared to $0.9 million or $1.10/boe in the fourth quarter of 2022. Gross G&A expense (before capitalized G&A expense and overhead recoveries) was lower than the the prior year ($2.1 million in the fourth quarter of 2023 compared to $2.4 million in the fourth quarter of 2022) due to lower staffing costs than the prior year period.

For the year ended December 31, 2023, net G&A expense was $4.2 million ($1.11/boe), which is higher on a total basis than the $3.4 million ($1.22/boe) for the prior year comparative period (9% decrease on a per boe basis). For the year ended December 31, 2023 gross G&A expense was $7.1 million compared to $6.7 million in the prior year. The 6% increase is mainly due to increased administrative costs (mainly legal costs).

SHARE-BASED COMPENSATION EXPENSE

The following table illustrates the Company's share-based compensation expense which is shown net of capitalized costs directly related to exploration and development activities:

Share-Based Compensation Expense ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Gross share-based compensation expense	**560**	614	**2,640**	1,630
Capitalized share-based compensation expense	**(153)**	(184)	**(777)**	(489)
Share-based compensation expense	**407**	**430**	**1,863**	**1,141**

Share-based compensation expense (net of capitalized portion) was $0.41 million for the fourth quarter of 2023, which is 5% lower than the $0.43 million recognized in the fourth quarter of the prior year. For the year ended December 31, 2023, net share-based compensation expense was $1.86 million, which is 63% higher than the $1.14 million in the prior year comparative period. The increase in stock based compensation expense for 2023 compared to the prior year is due to the Company's higher stock price in 2022 when the options were granted resulting in a higher value of stock options.

FINANCE EXPENSE

The following table illustrates the Company's finance expense which includes cash and non-cash expenses:

Finance Expense ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Interest expense	**1,117**	809	**4,205**	2,175
Foreign exchange loss (gain)	**—**	—	**—**	3
Finance fees	**129**	177	**596**	993
Deferred financing costs	**66**	137	**376**	430
Accretion on decommissioning obligations	**321**	310	**1,277**	1,066
Total finance expense	**1,633**	**1,433**	**6,454**	**4,667**

Fourth quarter total finance expense was $1.6 million in 2023, comprised of $0.3 million of non-cash accretion of its decommissioning obligations, $0.1 million of deferred financing costs, $1.1 million of cash interest expense and $0.13 million of finance fees. In the fourth quarter of 2022, the Company incurred total finance expense of $1.4 million, comprised of $0.3 million in non-cash accretion of its decommissioning obligation, $0.8 million cash interest expense, $0.2 million of finance fees, and $0.1 million of deferred financing fee amortization. The increase in total finance expense in the fourth quarter of 2023 is mainly due to the increased interest expense.

The Company incurred total finance expense of $6.5 million for the year ended December 31, 2023, which is 38% higher than the $4.7 million for the prior year. The increase in total finance expense is due to a higher first lien loan balance throughout 2023 as a result of the capital activity during the year.

DEPLETION AND DEPRECIATION

The following table compares depletion and depreciation expense recorded in the reporting periods shown:

Depletion and Depreciation Expense ($000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Depletion and depreciation expense	**10,292**	10,658	**46,623**	33,277
Depletion and depreciation expense ($/boe)	**11.81**	12.71	**12.40**	11.99

Depletion and depreciation expense is calculated on a unit-of-production (boe) basis. This fluctuates period to period primarily as a result of changes in the underlying proved plus probable reserve base and in the amount of costs subject to depletion and depreciation, including future development cost. Such costs are segregated and depleted on an area by area basis relative to the respective underlying proved plus probable reserve base.

Petrus recorded depletion and depreciation expense in the fourth quarter of 2023 of $10.3 million or $11.81/boe, compared to the fourth quarter of 2022, when $10.7 million or $12.71/boe was recorded.

For the year ended December 31, 2023, the Company recorded $46.6 million or $12.40/boe, compared to $33.3 million or $11.99 per boe for the prior year comparative period.

The increase in the depletion expense for the year ended December 31, 2023 compared to the prior year is due to higher production in 2023.

DEFERRED TAX

For the three months and year ended December 31, 2023, the Company recognized an income tax recovery of $19.6 million. The most significant component of the recovery was the reversal of a previous valuation allowance taken on the Company's non-operating losses and temporary differences. The recognition of the deferred tax asset is supported by projected taxable income in future periods based on cash flows from the Company's proved reserves, as evaluated by the Company's independent reserve evaluators.

SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares. The Company has not issued any preferred shares. The following table details the number of issued and outstanding common shares and for the periods shown:

Share Capital (000s)	Three months ended December 31, 2023	Three months ended December 31, 2022	Twelve months ended December 31, 2023	Twelve months ended December 31, 2022
Weighted average common shares outstanding				
Basic	**123,812**	122,545	**123,469**	115,189
Fully diluted	**124,840**	127,600	**126,436**	119,525
Common shares outstanding				
Basic	**124,266**	123,239	**124,266**	123,239
Fully diluted	**134,542**	133,377	**134,542**	133,377
Stock options outstanding	**8,617**	8,520	**8,617**	8,520

At December 31, 2023, the Company had 124,266,370 common shares and 8,616,900 stock options outstanding. As at the date of this MD&A, the Company had 124,270,972 common shares and 8,527,025 stock options outstanding.

Dividends

On October 10, 2023, the Company declared a special dividend of $0.03 per common share totaling $3.7 million that was paid in November 2023. During the year ended December 31, 2023, the Company declared a monthly dividend of $0.01 per common share totaling $1.2 million that was paid in January 2024.

Normal Course Issuer Bid ("NCIB")

On June 21, 2023, the Company announced the approval of its NCIB by the Toronto Stock Exchange ("the TSX"). The 2023 NCIB allows the Company to purchase up to 6,192,426 common shares over a period of twelve months commencing June 28, 2023.

Purchases are made on the open market through the TSX or alternative platforms at the market price of such common shares. All common shares purchased under the NCIB are cancelled. The total cost paid, including commissions and fees, is first charged to share capital to the extent of the average carrying value of the Company's common shares and the excess paid is recorded to retained earnings and any shortfall is recorded to contributed surplus.

Deferred share units

The Company has a deferred share unit plan in place whereby it may issue deferred share units ("DSUs") to directors of the Company. At December 31, 2023, 1,658,837 DSUs were issued and outstanding (December 31, 2022 – 1,618,702). As of the date of this MD&A 1,684,756 DSUs were issued and outstanding. Each DSU entitles the participants to receive, at the Company's discretion, either common shares or a cash equivalent to the number of DSUs multiplied by the current trading price of the equivalent number of common shares. All DSUs vest and become payable upon retirement of the director. The DSUs are included as equity as the Company does not intend to settle the DSUs for cash.

On each date that a dividend payment is made, holders of DSUs are credited with additional DSUs, which the number of additional DSUs is calculated by dividing the dividends that would have been paid to such holder if the DSUs held at the record date of the cash dividend had been common shares, by the fair market value of the common shares on the date on which the dividends are paid on the common shares.

Rights Offering

During the second quarter of 2022, the Company completed a rights offering (the "Rights Offering") where the Company issued approximately 14.8 million common shares at $1.35 per share for aggregate gross proceeds to the Company of approximately $20.0 million. The issuance costs were estimated to be $0.3 million and the net proceeds of $19.6 million were utilized for debt repayment and towards working capital.

The Company entered into a standby purchase agreement with each of Don Gray, Stuart Gray and Glen Gray (collectively, the "Stand-By Guarantors"). The Rights Offering was oversubscribed by 84% and as a result, the Stand-By Guarantors did not acquire any common shares in connection with the Rights Offering pursuant to their stand-by commitments. The Company had approximately 121.7 million shares outstanding following the Rights Offering with the Stand-By Guarantors owning approximately 71% of the outstanding shares.

Property Acquisition
During the first quarter of 2022, the Company completed an asset acquisition. The assets were acquired for share consideration of $15.2 million (10 million common shares of Petrus at $1.52 per share on closing date).

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2023, Petrus had two debt instruments outstanding; a reserve-based, secured operating revolving loan facility with an Alberta-based financial institution (the “Revolving Loan Facility” or “RLF”) and a second lien secured term facility (the "Second Lien Facility").

Revolving Loan Facility
At December 31, 2023, the RLF was comprised of a $60.0 million operating facility payable on demand by the lender. The amount of the RLF is subject to a borrowing base review performed on a semi-annual basis by the lender, based primarily on reserves and commodity prices estimated by the lenders as well as other factors. During the fourth quarter of 2023, the Company's lender completed the semi-annual borrowing base redetermination and increased the borrowing limit from $45 million to $60 million. The next semi-annual review is due on May 31, 2024.

At December 31, 2023, the Company had a $0.7 million letter of credit outstanding against the RLF (December 31, 2022 – $0.6 million) and had drawn $24.2 million against the RLF (December 31, 2022 – $4.6 million).

Second Lien Facility
At December 31, 2023 the Company had $25.0 million outstanding on the $25 million Second Lien Facility. The Second Lien Facility is a three-year term facility (maturity date May 31, 2025 with an option to the borrower to extend by an additional two years) with a fixed interest rate of 11% per annum and can be repaid at the discretion of the Company after the first year. The Second Lien Facility is a related party transaction with a major shareholder who owns approximately 21% of the outstanding shares of the Company (see note 22 of the Company's audited consolidated financial statements for the year ended December 31, 2023). The total interest paid in 2023 to the major shareholder, related to the Second Lien facility, was $2.8 million.

Debt Settlement - Term Loan & Revolving Credit Facility
During 2022, the Company entered into agreements with new lenders to the Company, providing two new credit facilities, as described above (the “New Credit Facilities”), totaling $55 million. The New Credit Facilities, together with the net proceeds of the Company's Rights Offering (described above), were used to repay in full all amounts owing under the Company's previous revolving credit facility. The New Credit Facilities closed in May 2022.

Financial Covenants
The Company's RLF is subject to certain financial covenants. The following definitions are used in the covenant calculations for the debt instrument:

Working Capital
Working Capital means Current Assets to Current Liabilities whereby Current Assets means on any date of determination, the current assets of Petrus that would, in accordance with IFRS, be classified as of that date as current assets plus any undrawn availability under the RLF, less any non-cash amount required to be included in current assets as the result of the application of IFRS including non-cash commodity and interest rate hedges assets and liabilities and whereby Current Liabilities means, on any date of determination, the liabilities of Petrus that would, in accordance with IFRS, be classified as of that date as current liabilities, excluding (a) non-cash obligations under IFRS including non-cash commodity and interest rate hedges assets and liabilities, and (b) the current portion of long-term debt.

Working Capital Ratio means the ratio of Current Assets to Current Liabilities as defined above, less any amounts outstanding under the Company's RLF.

The key financial covenants as at December 31, 2023 are summarized in the following table. At December 31, 2023 the Company is in compliance with all financial covenants.

Financial Covenant Description	Required Ratio	As at December 31, 2023
Working Capital Ratio	Over 1.0	1.5

Liquidity

At December 31, 2023, the Company had a working capital deficiency (excluding non-cash risk management assets and liabilities) of $39.3 million as the Company had $34.0 million in current accounts payable due to the substantial increase in capital activity during the third and fourth quarters of 2023. The Company plans to remediate the working capital deficiency by utilizing the available borrowing room under its RLF and cash flow from operating activities. For the year ended December 31, 2023, the Company generated cash flow from operating activities of $74.4 million.

Contractual Maturities

The following are the contractual maturities of financial liabilities as at December 31, 2023:

$000s	Total	< 1 year	1-5 years
Accounts payable and accrued liabilities	34,003	34,003	—
Risk management liability	396	396	—
Bank indebtedness	228	228	—
Revolving loan facility	26,520	26,520	—
Lease obligations (discounted)	363	258	105
Long term debt	27,984	2,313	25,671
Total	**89,494**	**63,718**	**25,776**

Commitments

The commitments for which the Company is responsible are as follows:

$000s	Total	< 1 year	1-5 years	> 5 years
Firm service transportation	**9,386**	**2,799**	**6,587**	**—**

Risk Management

Petrus is engaged in the acquisition, development, exploration and exploitation of oil and natural gas in western Canada. The Company is exposed to a number of risks, both financial and operational, through the pursuit of its strategic objectives. Actively managing these risks improves the ability to effectively execute Petrus' business strategy. Financial risks associated with the oil and natural gas industry include fluctuations in commodity prices, interest rates, inflation rates, currency exchange rates and the cost of goods and services. Financial risks also include third party credit risk and liquidity risk. Operational risks include reservoir performance uncertainties, competition, regulatory, environment and safety concerns.

For a more in-depth discussion of risk management, see notes 11 and 16 of the Company's December 31, 2023 audited consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

($000s unless otherwise noted)	Dec. 31, 2023	Sept. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2022	Sept. 30, 2022	Jun. 30, 2022	Mar. 31, 2022
Average Production								
Natural gas (mcf/d)	39,891	42,045	44,010	45,237	33,201	28,107	30,913	29,530
Oil (bbl/d)	1,218	1,316	1,670	2,192	2,458	957	1,073	1,250
NGLs (bbl/d)	1,607	1,556	1,486	1,654	1,121	997	1,055	1,207
Total (boe/d)	**9,474**	**9,880**	**10,492**	**11,385**	**9,113**	**6,639**	**7,280**	**7,379**
Total (boe)	**871,567**	**908,985**	**954,738**	**1,024,645**	**838,375**	**610,722**	**662,456**	**664,010**
Financial Results								
Oil and natural gas revenue	26,747	28,273	29,266	41,319	48,590	28,701	42,119	32,940
Royalty expense	(4,167)	(3,061)	(3,492)	(6,534)	(6,636)	(7,228)	(5,721)	(4,576)
Gain (loss) on risk management activities	—	—	32	1,490	(1,056)	(497)	(4,476)	—
Net oil and natural gas revenue	**22,580**	**25,212**	**25,806**	**36,275**	**40,898**	**20,976**	**31,922**	**28,364**
Transportation expense	(1,271)	(1,401)	(1,341)	(2,102)	(1,743)	(1,155)	(1,434)	(1,440)
Operating expense	(4,419)	(6,086)	(5,566)	(7,434)	(5,753)	(5,171)	(5,249)	(4,492)
Operating netback[1]	**16,890**	**17,725**	**18,899**	**26,739**	**33,402**	**14,650**	**25,239**	**22,432**
Realized gain (loss) on financial derivatives	1,737	1,102	3,398	1,814	2,421	610	—	(4,632)
Other income (cash)	(161)	34	37	169	186	30	28	47
General and administrative expense	(319)	(1,158)	(1,476)	(1,230)	(926)	(793)	(1,127)	(543)
Cash finance expense	(1,246)	(1,148)	(1,269)	(1,140)	(987)	(528)	(969)	(689)
Decommissioning expenditures	(376)	(312)	(549)	(136)	21	(180)	37	(14)
Corporate netback and funds flow[1]	**16,525**	**16,243**	**19,040**	**26,216**	**34,117**	**13,789**	**23,208**	**16,601**
Oil and natural gas revenue	**26,747**	**28,273**	**29,266**	**41,319**	**48,590**	**28,701**	**42,119**	**32,940**
Per share - basic	0.22	0.23	0.24	0.33	0.40	0.24	0.38	0.33
Per share - fully diluted	0.21	0.23	0.23	0.32	0.38	0.23	0.36	0.32
Net income (loss)	**39,708**	**(11,293)**	**5,043**	**17,273**	**22,097**	**9,822**	**18,046**	**10,903**
Per share - basic	0.32	(0.09)	0.04	0.14	0.18	0.08	0.16	0.11
Per share - fully diluted	0.32	(0.09)	0.04	0.14	0.17	0.08	0.15	0.11
Common shares outstanding (000s)								
Basic	124,266	123,867	123,849	123,711	123,239	122,197	122,017	106,907
Fully diluted	134,542	134,436	134,423	133,916	133,377	131,482	131,302	113,883
Weighted average shares outstanding (000s)								
Basic	123,812	123,743	123,752	123,416	122,545	122,058	111,795	99,189
Fully diluted	124,840	123,743	127,040	127,358	127,600	126,822	117,203	103,250
Total assets	**437,842**	**380,100**	**383,231**	**403,276**	**381,057**	**356,050**	**302,472**	**308,744**

[1] *Non-GAAP measure. Refer to "Non-GAAP and Other Financial Measures".*

The oil and natural gas exploration and production industry is cyclical in nature. Petrus' financial position, results of operations and corporate netback are affected by commodity prices, exchange rates, Canadian commodity price differentials and production levels. Petrus' average quarterly production has increased from 7,379 boe/d in the first quarter of 2022 to 9,474 boe/d in the fourth quarter of 2023. The 28% production increase is attributable to Petrus' shift in focus back to production growth and an increased capital program.

SELECTED ANNUAL INFORMATION

($000s unless otherwise noted)

For the year ended,	December 31, 2023	December 31, 2022	December 31, 2021
Oil and natural gas revenue	**125,605**	**152,350**	**81,268**
Per share - basic	1.02	1.32	1.30
Per share - fully diluted	0.99	1.27	1.25
Net income	**50,731**	**60,868**	**114,556**
Per share - basic	0.41	0.53	1.83
Per share - fully diluted	0.40	0.51	1.76
Common shares outstanding (000s)			
Basic	124,266	123,239	96,708
Fully diluted	134,542	133,377	103,889
Weighted avg. shares outstanding (000s)			
Basic	123,469	115,189	62,557
Fully diluted	126,436	119,525	65,207
Total assets	**437,842**	**381,057**	**290,492**
Non-current liabilities	**60,926**	**63,021**	**42,172**

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The Company's critical accounting estimates can be read in note 2 to the Company's audited consolidated financial statements as at and for the year ended December 31, 2023.

OTHER FINANCIAL INFORMATION

Material accounting policies

The Company's material accounting policies can be read in note 3 of the Company's audited consolidated financial statements as at and for the year ended December 31, 2023.

New standards and interpretations

The Company has not adopted any new standards and interpretations for the year ended December 31, 2023.

Disclosure Controls and Procedures

Petrus' Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. The Chief Executive Officer and Chief Financial Officer of Petrus have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's DC&P as at December 31, 2023 and have concluded that the Company's DC&P are effective at December 31, 2023 for the foregoing purposes.

Internal Control over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in NI 52-109, includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of assets of Petrus; (ii) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Petrus are being made in accordance with authorizations of management and Directors of Petrus; and (iii) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Petrus. For the year ended December 31, 2023, they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework used to design the Company's ICFR is the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. There has not been any change in Petrus' ICFR that occurred during the period beginning October 1, 2023 and ended on December 31, 2023 that has materially affected, or is reasonably likely to materially affect, Petrus' ICFR.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Petrus conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2023. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as at December 31, 2023, Petrus maintained effective ICFR. It should be noted that while the Chief Executive Officer and Chief Financial Officer believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the control system will prevent all errors or fraud.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A makes reference to the terms "operating netback" (on an absolute and $/boe basis), "corporate netback" (on an absolute and $/boe basis), "funds flow" (on an absolute, per share (basic and fully diluted) and $/boe basis) and "net debt". These non-GAAP and other financial measures are not recognized measures under GAAP (IFRS) and do not have a standardized meaning prescribed by GAAP (IFRS). Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. These non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS as indicators of our performance. Management uses these non-GAAP and other financial measures for the reasons set forth below.

Operating Netback

Operating netback is a common non-GAAP financial measure used in the oil and natural gas industry which is a useful supplemental measure to evaluate the specific operating performance by product type at the oil and natural gas lease level. The most directly comparable GAAP measure to operating netback is oil and natural gas revenue. Operating netback is calculated as oil and natural gas revenue less royalty expenses, operating expenses and transportation expenses, plus or minus the gain (loss) on risk management activities. See below and under "Summary of Quarterly Results" for a reconciliation of operating netback to oil and natural gas revenue.

Operating netback ($/boe) is a non-GAAP ratio used in the oil and natural gas industry which is a useful supplemental measure to evaluate the specific operating performance by product type at the oil and natural gas lease level . It is calculated as operating netbacks divided by weighted average daily production on a per boe basis. See below.

Corporate Netback and Funds Flow

Corporate netback or funds flow is a common non-GAAP financial measure used in the oil and natural gas industry which evaluates the Company's profitability at the corporate level. Corporate netback and funds flow are used interchangeably. Petrus analyzes these measures on an absolute value and on a per unit (boe) and per share (basic and fully diluted) basis as non-GAAP ratios. Management believes that funds flow and corporate netback provide information to assist a reader in understanding the Company's profitability relative to current commodity prices. They are calculated as the operating netback less general and administrative expense, cash finance expense, decommissioning expenditures, plus other income and the net realized gain (loss) on financial derivatives and risk management activities. See below and under "Summary of Quarterly Results" for a reconciliation of funds flow and corporate netback to oil and natural gas revenue.

Corporate netback ($/boe) or funds flow ($/boe) is a non-GAAP ratio used in the oil and natural gas industry which evaluates the Company's profitability at the corporate level. Management believes that funds flow ($/boe) or corporate netback ($/boe) provide information to assist a reader in understanding the Company's profitability relative to current commodity prices. It is calculated as corporate netbacks or funds flow divided by weighted average daily production on a per boe basis. See below.

Funds flow per share (basic and fully diluted) is comprised of funds flow divided by basic or fully diluted weighted average common shares outstanding.

Free Funds Flow

Free funds flow is a common non-GAAP financial measure used in the oil and natural gas industry that evaluates the Company's efficiency and liquidity. Free funds flow represents the funds after capital expenditures available to manage debt levels and pay dividends. Petrus calculates free funds flow as funds flow generated during the period less capital expenditures. The most directly comparable financial measure that is disclosed in the Company's primary financial statements is oil and natural gas revenue. See below for a reconciliation of free funds flow to oil and natural gas revenue.

	Three months ended December 31, 2023		Three months ended December 31, 2022		Twelve months ended December 31, 2023		Twelve months ended December 31, 2022	
	$000s	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**
Oil and natural gas revenue	26,747	30.70	48,590	57.96	125,605	33.41	152,350	54.89
Royalty expense	(4,167)	(4.78)	(6,636)	(7.92)	(17,255)	(4.59)	(24,161)	(8.70)
Gain (loss) on risk management activities	—	—	(1,056)	(1.26)	1,522	0.40	(6,029)	(2.17)
Net oil and natural gas revenue	**22,580**	**25.92**	**40,898**	**48.78**	**109,872**	**29.22**	**122,160**	**44.02**
Transportation expense	(1,271)	(1.46)	(1,743)	(2.08)	(6,115)	(1.63)	(5,772)	(2.08)
Operating expense	(4,419)	(5.07)	(5,753)	(6.86)	(23,505)	(6.25)	(20,665)	(7.45)
Operating netback	**16,890**	**19.39**	**33,402**	**39.84**	**80,252**	**21.34**	**95,723**	**34.49**
Realized gain (loss) on financial derivatives	1,737	1.99	2,421	2.89	8,051	2.14	(1,601)	(0.58)
Other income(1)	(161)	(0.18)	186	0.22	79	0.02	291	0.10
General & administrative expense	(319)	(0.37)	(926)	(1.10)	(4,183)	(1.11)	(3,389)	(1.22)
Cash finance expense	(1,246)	(1.43)	(987)	(1.18)	(4,801)	(1.28)	(3,171)	(1.14)
Decommissioning expenditures	(376)	(0.43)	21	0.03	(1,374)	(0.37)	(137)	(0.05)
Funds flow and corporate netback	**16,525**	**18.97**	**34,117**	**40.70**	**78,024**	**20.74**	**87,716**	**31.60**
Capital expenditures	**(32,029)**	**(36.73)**	**(37,792)**	**(45.10)**	**(86,843)**	**(23.10)**	**(96,744)**	**(34.85)**
Free funds flow	**(15,504)**	**(17.76)**	**(3,675)**	**(4.40)**	**(8,819)**	**(2.36)**	**(9,028)**	**(3.25)**

(1)Excludes non-cash government grant related to decommissioning expenditures.

Net Debt

Net debt is a non-GAAP financial measure and is calculated as the sum of long term debt and working capital (current assets and current liabilities), excluding the current financial derivative contracts and current portion of the lease obligation and decommissioning obligation. Petrus uses net debt as a key indicator of its leverage and strength of its balance sheet. Net debt is reconciled, in the table below, to long-term debt which is the most directly comparable GAAP measure.

($000s)	**As at Dec. 31, 2023**	**As at Sept. 30, 2023**	**As at Jun. 30, 2023**	**As at Mar. 31, 2023**	**As at Dec. 31, 2022**
Long-term debt	25,000	25,000	25,000	25,000	25,000
Current assets	(30,805)	(19,375)	(28,150)	(31,309)	(29,849)
Current liabilities	61,755	40,636	30,032	50,336	51,395
Current financial derivatives	8,374	(3,397)	10,224	9,328	4,502
Current portion of lease obligation	(258)	(254)	(249)	(244)	(240)
Current portion of decommissioning obligation	(1,470)	(359)	(671)	(1,357)	(1,357)
Net debt	**62,596**	**42,251**	**36,186**	**51,754**	**49,451**

Net debt to funds flow ratio is a non-GAAP ratio used as a key indicator of our leverage and strength of our balance sheet. It is calculated as net debt divided by funds flow for the relevant period.

OIL AND GAS DISCLOSURES

Our oil and gas reserves statement for the year ended December 31, 2023, which includes disclosure of our oil and natural gas reserves and other oil and natural gas information in accordance with NI 51-101, is contained in the AIF, which will be filed on SEDAR+ at www.sedarplus.ca.

Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Petrus' operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment or other purposes.

ADVISORIES

Basis of Presentation

Financial data presented above has largely been derived from the Company's financial statements, prepared in accordance with GAAP which require publicly accountable enterprises to prepare their financial statements using IFRS. Accounting policies adopted by the Company are set out in the notes to the audited consolidated financial statements as at and for the twelve months ended December 31, 2023. The reporting and the measurement currency is the Canadian dollar. All financial information is expressed in Canadian dollars, unless otherwise stated.

Forward-Looking Statements

Certain information regarding Petrus set forth in this MD&A contains forward-looking statements within the meaning of applicable securities law, that involve substantial known and unknown risks and uncertainties. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. Such statements represent Petrus' internal projections, estimates, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are only predictions and actual events or results may differ materially. Although Petrus believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause Petrus' actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Petrus.

In particular, forward-looking statements included in this MD&A include, but are not limited to, statements with respect to: the timing for completion activities for wells drilled during the fourth quarter of 2023; the Company's risk management and hedging strategy and its objectives, including our ability to mitigate commodity price risk and provide stability and sustainability to our economic returns, funds flow and capital development plan; our belief that our risk management contracts are effective economic hedges of our underlying business transactions; that our risk management contracts provide protection from significant changes in crude oil and natural gas commodity prices for 2024 and 2025; and the Company's intention not to settle its DSUs for cash. In addition, statements relating to "reserves" 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.

These forward-looking statements are subject to numerous risks and uncertainties, most of which are beyond the Company's control, including: the risk that the Company is unable to generate strong cash flow in the future and as a result, it has little or no cash to return to shareholders or reduce debt; the impact of general economic conditions; volatility in market prices for crude oil, NGLs and natural gas; industry conditions; currency fluctuation; changes in interest rates and inflation rates; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition; the lack of availability of qualified personnel or management; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; stock market volatility; ability to access sufficient capital from internal and external sources; and the other risks and uncertainties described in the AIF. With respect to forward-looking statements contained in this MD&A, Petrus has made assumptions regarding: future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment and services; effects of regulation by governmental agencies; the effects of inflation on our costs and profitability; future interest rates; and future operating costs. Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide investors with a more complete perspective on Petrus' future operations and such information may not be appropriate for other purposes. Petrus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive therefrom. Readers are cautioned that the foregoing lists of factors are not exhaustive.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Petrus' prospective results of operations including, without limitation, its target net debt to funds flow ratio, which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on FOFI. Petrus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these FOFI, or if any of them do so, what benefits Petrus will derive therefrom. Petrus has included the FOFI in order to provide readers with a more complete perspective on Petrus' future operations and such information may not be appropriate for other purposes.

These forward-looking statements are made as of the date of this MD&A and the Company disclaims any intent or obligation to update any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

BOE Presentation

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. Petrus uses the 6:1 boe measure which is the approximate energy equivalence of the two commodities at the burner tip. Boe's do not represent an economic value equivalence at the wellhead and therefore may be a misleading measure if used in isolation.

Abbreviations

$000's	*thousand dollars*
$/bbl	*dollars per barrel*
$/boe	*dollars per barrel of oil equivalent*
$/GJ	*dollars per gigajoule*
$/mcf	*dollars per thousand cubic feet*
bbl	*barrel*
mbbl	*thousand barrel*
bbl/d	*barrels per day*
boe	*barrel of oil equivalent*
mboe	*thousand barrel of oil equivalent*
mmboe	*million barrel of oil equivalent*
boe/d	*barrel of oil equivalent per day*
GJ	*gigajoule*
GJ/d	*gigajoules per day*
mcf	*thousand cubic feet*
mcf/d	*thousand cubic feet per day*
mmcf/d	*million cubic feet per day*
bcf	*billion cubic feet*
NGLs	*natural gas liquids*
WTI	*West Texas Intermediate*

CONSOLIDATED ANNUAL FINANCIAL STATEMENTS

As at and for the years ended December 31, 2023 and 2022

Independent auditor's report

To the Audit Committee of Petrus Resources Ltd.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Petrus Resources Ltd. and its subsidiaries (together, the Company) as at December 31, 2023 and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (IFRS Accounting Standards).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated balance sheet as at December 31, 2023;
- the consolidated statement of net income and comprehensive income for the year then ended;
- the consolidated statement of changes in shareholders' equity for the year then ended;
- the consolidated statement of cash flows for the year then ended; and
- the notes to the consolidated financial statements, comprising material accounting policy information and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
Suncor Energy Centre, 111 5th Avenue South West, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T.: +1 403 509 7500, F.: +1 403 781 1825, Fax to mail: ca_calgary_main_fax@pwc.com

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2023. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
The impact of proved and probable reserves on property, plant and equipment (PP&E) of the Ferrier cash generating unit (CGU) *Refer to note 2 – Basis of Presentation, note 3 – Material Accounting Policies, note 4 – Determination of Fair Values and note 7 – Property, Plant and Equipment to the consolidated financial statements.* The Company had $355.1 million of PP&E as at December 31, 2023 and recorded depletion and depreciation (D&D) expense of $46.6 million for the year then ended. Petroleum and natural gas assets within PP&E are depleted using the unit of production method based on either proved developed producing or proved and probable reserves. The majority of the petroleum and natural gas assets relate to the Ferrier CGU and are depleted based on proved and probable reserves. PP&E is aggregated into CGUs for purposes of impairment testing. Management assesses its CGUs for indicators of impairment each quarter. If indicators of impairment exist, management estimates the recoverable amounts of impacted CGUs. If the carrying amount of a CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income. As at December 31, 2023, management identified indicators of impairment for its Ferrier CGU and conducted an impairment test. No impairment was	Our approach to addressing the matter included the following procedures, among others: • The work of management's experts was used in performing the procedures to evaluate the reasonableness of the proved and probable reserves used to determine D&D expense and the recoverable amount of the Ferrier CGU. As a basis for using this work, the competence, capabilities and objectivity of management's experts were evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's experts, tests of the data used by management's experts and an evaluation of their findings. • Tested how management determined the recoverable amount of the Ferrier CGU and proved and probable reserves, which included the following: – Evaluated the appropriateness of the methods used by management in making these estimates. – Tested the data used in determining these estimates. – Evaluated the reasonableness of key assumptions used in developing these estimates:

Key audit matter	How our audit addressed the key audit matter
recognized by management as a result of this impairment test. Management determined the recoverable amount of the Ferrier CGU based on its fair value less costs to disposal using a discounted after-tax future cash flow model based on proved and probable reserves. Proved and probable reserves are evaluated by the Company's independent reservoir engineers (management's experts). Key assumptions used by management to determine the recoverable amount of the Ferrier CGU and the proved and probable reserves include expected future production volumes, forecasted commodity prices, future development costs, future operating costs and the discount rate, as applicable. We determined that this is a key audit matter due to (i) the significant judgment by management, including the use of management's experts, when estimating proved and probable reserves and developing the expected future cash flows used to determine the recoverable amount of the Ferrier CGU; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures relating to the significant assumptions; and (iii) the audit effort that involved the use of professionals with specialized skill and knowledge in the field of valuation.	o Expected future production volumes, future development costs and future operating costs by considering the past performance of the Ferrier CGU, and whether these assumptions were consistent with evidence obtained in other areas of the audit. o Forecasted commodity prices by comparing those forecasts with other reputable third party industry forecasts. o The discount rate, with the assistance of professionals with specialized skill and knowledge in the field of valuation. • Recalculated the unit-of-production rates used to calculate D&D expense for the Ferrier CGU.

Comparative information

The consolidated financial statements of the Company for the year ended December 31, 2022 were audited by another auditor who expressed an unmodified opinion on those consolidated financial statements on March 14, 2023.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis, which we obtained prior to the date of this auditor's report and the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, which is expected to be made available to us after that date.

Our opinion on the consolidated 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 consolidated 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 consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard. When we read the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, if we conclude that there is a material misstatement therein, we are required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

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

In preparing the consolidated 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 consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated 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 generally accepted auditing standards 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 consolidated financial statements.

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

- Identify and assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements, including the disclosures, and whether the consolidated 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 consolidated 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.

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

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

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 25, 2024

CONSOLIDATED BALANCE SHEETS

(Presented in 000's of Canadian dollars)

As at	December 31, 2023	December 31, 2022
ASSETS		
Current		
Cash	375	40
Other assets *(note 24)*	1,842	1,197
Deposits and prepaid expenses *(note 25)*	2,536	1,862
Accounts receivable *(note 16)*	17,282	22,248
Risk management asset *(note 11)*	8,770	4,502
Total current assets	**30,805**	**29,849**
Non-current		
Risk management asset *(note 11)*	1,685	619
Exploration and evaluation assets *(note 6)*	30,628	34,837
Property, plant and equipment *(note 7)*	355,103	315,752
Deferred income taxes *(note 23)*	19,621	—
Total non-current assets	**407,037**	**351,208**
Total assets	**437,842**	**381,057**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness	208	658
Revolving loan facility *(note 8)*	24,175	3,949
Accounts payable and accrued liabilities *(note 16)*	34,003	45,191
Dividends payable *(note 12)*	1,245	—
Risk management liability *(note 11)*	396	—
Decommissioning obligation *(note 10)*	1,470	1,357
Lease obligations *(note 9)*	258	240
Total current liabilities	**61,755**	**51,395**
Non-current liabilities		
Long term debt *(note 8)*	25,000	25,000
Lease obligations *(note 9)*	105	363
Decommissioning obligation *(note 10)*	35,821	37,658
Total liabilities	**122,681**	**114,416**
Shareholders' equity		
Share capital *(note 12)*	492,205	492,241
Contributed surplus	31,848	29,061
Deficit	(208,892)	(254,661)
Total shareholders' equity	**315,161**	**266,641**
Total liabilities and shareholders' equity	**437,842**	**381,057**

Commitments and contingencies (note 20)
See accompanying notes to the consolidated financial statements

Approved by the Board of Directors,

(signed) "Don T. Gray"

Don T. Gray
Chairman

(signed) "Donald Cormack"

Donald Cormack
Director

CONSOLIDATED STATEMENTS OF NET INCOME AND COMPREHENSIVE INCOME

(Presented in 000's of Canadian dollars, except per share amounts)

	Year ended December 31, 2023	Year ended December 31, 2022
REVENUE		
Oil and natural gas sales *(note 21)*	**125,605**	**152,350**
Royalty expense	(17,255)	(24,161)
Gain (loss) on risk management activities *(notes 11 and 21)*	1,522	(6,029)
Net revenue *(note 21)*	**109,872**	**122,160**
Other income *(note 26)*	1,302	1,351
Net gain on financial derivatives *(note 11)*	12,989	6,008
Total income	**124,163**	**129,519**
EXPENSES		
Operating *(note 14)*	23,505	20,665
Transportation	6,115	5,772
General and administrative *(note 15)*	4,183	3,389
Share-based compensation *(note 12)*	1,863	1,141
Finance *(note 18)*	6,454	4,667
Exploration and evaluation *(note 6)*	4,706	421
Depletion and depreciation *(note 7)*	46,623	33,277
Unrealized (gain) on foreign exchange	(396)	—
Gain on sale of assets	—	(681)
Total expenses	**93,053**	**68,651**
INCOME BEFORE INCOME TAX	**31,110**	**60,868**
Income tax recovery *(note 23)*	19,621	—
NET INCOME AND COMPREHENSIVE INCOME	**50,731**	**60,868**
Net income per common share		
Basic *(note 13)*	0.41	0.53
Diluted *(note 13)*	0.40	0.51

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Presented in 000's of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Total
Balance, December 31, 2021	**455,908**	**27,846**	**(315,529)**	**168,225**
Net income	—	—	60,868	60,868
Common shares issued for property acquisition	15,200	—	—	15,200
Common shares issued for rights offering	20,003	—	—	20,003
Issuance of common shares	1,427	(415)	—	1,012
Share issue costs	(297)	—	—	(297)
Share-based compensation *(note 12)*	—	1,630	—	1,630
Balance, December 31, 2022	**492,241**	**29,061**	**(254,661)**	**266,641**
Net income	—	—	50,731	50,731
Common shares repurchased *(note 12)*	(789)	—	—	(789)
Issuance of common shares *(note 12)*	753	147	—	900
Share-based compensation *(note 12)*	—	2,640	—	2,640
Dividends *(note 12)*	—	—	(4,962)	(4,962)
Balance, December 31, 2023	**492,205**	**31,848**	**(208,892)**	**315,161**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Presented in 000's of Canadian dollars)

	Year ended December 31, 2023	Year ended December 31, 2022
OPERATING ACTIVITIES		
Net income	**50,731**	**60,868**
Adjust items not affecting cash:		
Exploration and evaluation expense *(note 6)*	4,706	421
Unrealized (gain) loss on financial derivatives *(note 11)*	(4,938)	(7,609)
Other income *(note 26)*	(1,223)	(1,060)
Gain on sale of assets *(note 7)*	—	(681)
Share-based compensation *(note 12)*	1,863	1,141
Depletion and depreciation *(note 7)*	46,623	33,277
Unrealized (gain) loss on foreign exchange	(396)	—
Non-cash finance expenses *(note 18)*	1,653	1,496
Recovery of future income taxes on *(note 23)*	(19,621)	—
Decommissioning expenditures *(note 10)*	(1,374)	(137)
Funds flow	**78,024**	**87,716**
Change in operating non-cash working capital *(note 19)*	(3,654)	12,891
Cash flows from operating activities	**74,370**	**100,607**
FINANCING ACTIVITIES		
Shares repurchased *(note 12)*	(285)	—
Issuance of shares *(note 12)*	772	21,132
Cash dividends paid *(note 12)*	(3,716)	—
Draw down (repayment) of revolving loan facility	20,623	(53,094)
Repayment of bank indebtedness	(451)	—
Transaction costs on debt	(315)	(518)
Repayment of lease liabilities *(note 9)*	(277)	(217)
Proceeds from long term debt *(note 8)*	—	25,000
Change in financing non-cash working capital *(note 19)*	—	—
Cash flows from (used) in financing activities	**16,351**	**(7,697)**
INVESTING ACTIVITIES		
Property and equipment acquisitions *(note 7)*	(50)	243
Property and equipment dispositions *(note 7)*	150	—
Exploration and evaluation asset acquisition *(note 6)*	(1,064)	—
Exploration and evaluation asset expenditures *(note 6)*	(284)	(1,645)
Petroleum and natural gas property expenditures *(note 7)*	(85,386)	(94,921)
Other capital expenditures	(109)	(175)
Change in investing non-cash working capital *(note 19)*	(3,643)	(1,300)
Cash flows used in investing activities	**(90,386)**	**(97,798)**
Increase (decrease) in cash	335	(4,888)
Cash, beginning of year	40	4,928
Cash, end of year	**375**	**40**
Cash interest paid *(note 18)*	4,801	3,171
Cash taxes paid	—	—

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2023 and 2022

1. NATURE OF THE ORGANIZATION

Petrus Resources Ltd. (the "Company" or "Petrus") was incorporated under the laws of the Province of Alberta on November 25, 2015. The principal undertaking of Petrus is the investment in energy business-related assets. The operations of the Company consist of the acquisition, development, exploration and exploitation of these assets. These consolidated financial statements reflect only the Company's proportionate interest in such activities and are comprised of the Company and its subsidiaries, Petrus Resources Corp. and Petrus Resources Inc.

The Company's head office is located at 2400, 240 - 4th Avenue SW, Calgary, Alberta, Canada.

These consolidated financial statements, for the years ended December 31, 2023 and 2022, were approved by the Company's Audit Committee and Board of Directors on March 25, 2024.

2. BASIS OF PRESENTATION

Statement of Compliance
These consolidated financial statements have been prepared by management in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards").

Measurement Basis
These consolidated financial statements were prepared on the basis of historical cost except for financial derivatives which are measured at fair value. This method is consistent with the method used in prior years. These consolidated financial statements are presented in Canadian dollars.

Consolidation
These consolidated financial statements include the accounts of Petrus and its 100% owned subsidiaries, Petrus Resources Corp. and Petrus Resources Inc. Subsidiaries are consolidated from the date control is obtained until the date control ends. Control exists where the Company has power over the investee, exposure or rights to variable returns from the investee and the ability to use its power over the investee to affect returns. All intra-group balances and transactions are eliminated on consolidation.

Critical Accounting Estimates
The timely preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of the financial statements are outlined below.

i. **Depletion and reserve estimates**
Petroleum and natural gas assets are depleted on a unit of production basis at a rate calculated by reference to proved developed producing reserves or proved and probable reserves determined in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). For assets depleted based on proved and probable reserves, the calculation incorporates the estimated future cost of developing and extracting those reserves. Reserves are estimated using independent reservoir engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids for which recoverability in future years from known reservoirs is deemed to be technically feasible and which are considered commercially producible. Reserves estimates, although not reported as part of the Company's financial statements, can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion and depreciation, decommissioning liabilities, deferred taxes, asset impairments and business combinations.

An independent qualified reserves evaluator ("IQRE") performs evaluations of the Company's petroleum and natural gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable petroleum and natural gas reserves are based upon a number of variables and assumptions including expected future production volumes, forecasted commodity prices, future operating costs and future development costs, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available or as economic conditions change.

ii. **Impairment indicators and cash-generating units**
For purposes of impairment testing, exploration and evaluation assets and petroleum and natural gas assets are aggregated into cash-generating units ("CGUs"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment.

The recoverable amounts of CGUs and individual assets have been determined based on the higher of the value-in-use ("VIU") and fair value less costs of disposal (FVLCOD). These calculations require the use of estimates and assumptions, including expected future production volumes, forecasted commodity prices, future operating costs, future development costs and the discount rate . These assumptions are subject to change as new information becomes available and changes in economic conditions take place. Changes may impact the estimated life of the assets and economical reserves recoverable and may require a material adjustment to the carrying value of exploration and evaluation assets and petroleum and natural gas assets. The Company monitors internal and external indicators of impairment relating to its tangible assets.

iii. Technical feasibility and commercial viability of exploration and evaluation assets

The determination of technical feasibility and commercial viability, based on the presence of proved and probable reserves, results in the transfer of assets from exploration and evaluation assets to property, plant and equipment. As discussed above, the estimate of proved and probable reserves is inherently complex and requires significant judgment. Thus, any material change to reserve estimates could affect the technical feasibility and commercial viability of the underlying assets.

iv. Financial instruments

Financial instruments are subject to valuations at the end of each reporting period. Generally, the valuation is based on active and efficient markets. However, certain financial instruments may not be traded on an efficient market or the market may disappear or be subject to conditions that impede the efficiency of the market.

v. Decommissioning obligation

At the end of the operating life of the Company's facilities and properties and upon retirement of its petroleum and natural gas assets, decommissioning costs will be incurred by the Company. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and discount rates to determine the present value of these cash flows.

vi. Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in income or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods. Income taxes are subject to measurement uncertainty. Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws.

vii. Measurement of share-based compensation

Share-based compensation recorded pursuant to share-based compensation plans is subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

3. MATERIAL ACCOUNTING POLICIES

(a) Revenue recognition

Revenue from contracts with customers is recognized when or as Petrus satisfies a performance obligation by transferring a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids usually occurs at a point in time and coincides with title passing to the customer and the customer taking physical possession. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. Revenue from the sale of oil, natural gas and natural gas liquids is recorded net of royalties.

(b) Exploration & evaluation assets

Capitalization

All costs incurred after the rights to explore an area have been obtained, such as geological and geophysical costs, other direct costs of exploration (drilling, testing and evaluating the technical feasibility and commercial viability of extraction) and appraisal and including any directly attributable general and administration costs and share-based payments, are accumulated and capitalized as exploration and evaluation assets.
Certain costs incurred prior to acquiring the legal rights to explore are charged directly to net income (loss).

Depletion & depreciation

Exploration and evaluation costs are not amortized prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then the carrying value of the relevant exploration and evaluation asset will be reclassified as a property, plant and equipment asset into the CGU to which it relates, but only after the carrying value of the relevant exploration and evaluation asset has been assessed for impairment and, where appropriate, its carrying value adjusted. Technical feasibility and commercial viability are considered to be demonstrable when proved or probable reserves are determined to exist. If it is determined that technical feasibility and commercial viability have not been achieved in relation to the exploration and evaluation assets appraised, all other associated costs are written down to the recoverable amount in net income (loss).

Expired land leases included as undeveloped land in exploration and evaluation assets are recognized in exploration and evaluation cost in net income (loss) upon expiry and are considered prior to expiry. Management considers upcoming land lease expiries and may recognize the costs in advance of expiry.

Impairment

Indicators of impairment of exploration and evaluation assets are assessed at each reporting date which can include upcoming land lease expiries, third party land valuations and other information. When there are such indications, an impairment test is carried out and any resulting impairment loss is written off to net income (loss). The recoverable amount is the greater of fair value, less costs of disposal, or value-in-use.

(c) Property, plant and equipment

The Company's property, plant and equipment is comprised of petroleum and natural gas assets and corporate assets.

Capitalization

Petroleum and natural gas assets are measured at cost less accumulated depletion and depreciation and accumulated impairment losses, if any. Petroleum and natural gas assets consist of the purchase price and costs directly attributable to bringing the asset to the location and condition necessary for its intended use. Petroleum and natural gas assets include developing and producing interests such as land acquisitions, geological and geophysical costs, facility and production equipment, including any directly attributable general and administration costs and share-based payments and the initial estimate of the costs of dismantling and removing an asset and restoring the site on which it was located.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as developing and producing petroleum and natural gas interests when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves, and are accumulated on a field or geotechnical area basis. The cost of day-to-day servicing of an item of petroleum and natural gas assets is expensed in net income or net loss as incurred. Petroleum and natural gas assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from the disposal of an asset, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in net income or loss.

Depletion and depreciation

The costs for petroleum and natural gas properties, including related pipelines and facilities, are depleted using a unit-of-production method based on either proved developed producing or proved and probable reserves.

Petroleum and natural gas assets are not depleted until production commences. The depletion calculation includes actual production in the period and estimated proved developed producing reserves or estimated proved and probable reserves attributable to the assets being depleted, taking into account total capitalized costs plus estimated future development costs necessary to bring those reserves into production. For the purpose of these calculations, natural gas is converted to crude oil on an energy equivalent basis. Reserves are estimated using independent reservoir engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids for which recoverability in future years from known reservoirs is deemed to be technically feasible and which are considered commercially producible.

Corporate assets are recorded at cost less accumulated depreciation. Depreciation is calculated on a declining balance method so as to write off the cost of these assets, less estimated residual values, over their estimated useful lives consistent with the treatment used for tax purposes.

Impairment

Petrus' property, plant and equipment are grouped into CGUs based on separately identifiable and largely independent cash inflows considering geological characteristics, shared infrastructure and exposure to market risks. The CGUs are reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate that the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income (loss). Impairments of property, plant and equipment are reversed when there is significant evidence that the impairment has been reversed, but only to the extent of what the net carrying amount would have been had no impairment been recognized.

The assessment for impairment or impairment reversal entails comparing the carrying value of the CGU with its recoverable amount. The recoverable amount is the higher of FVLCOD and the VIU. VIU is estimated as the present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is the amount that would be realized from the disposition of an asset or CGU in an arm's length transaction between knowledgeable and willing parties. FVLCOD, is derived by estimating the discounted after-tax future net cash flows of the CGU based on forecast commodity prices and costs over the expected economic life of the reserves as estimated by an IQRE and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. In certain instances, the estimate of fair value may also consider an evaluation of comparable transaction metrics. VIU is assessed using the expected future cash flows discounted at a pre-tax rate.

(d) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and reclamation requirements. Costs related to these abandonment activities are estimated by management in consultation with the Company's engineers based on risk-adjusted current costs which take into consideration current technology in accordance with existing legislation and industry practices.

Decommissioning obligations are measured at the present value of the best estimate of expenditures required to settle the obligations at the reporting date. When the fair value of the liability is initially measured, the estimated cost, discounted using a risk-free rate, is capitalized by increasing the carrying amount of the related petroleum and natural gas assets. The increase in the provision due to the passage of time, or accretion, is recognized as a finance expense. Increases and decreases due to revisions in the estimated future cash flows are recorded as adjustments to the carrying amount of the related petroleum and natural gas assets.

Actual costs incurred upon settlement of the liability are charged against the obligation to the extent that the obligation was previously established. The carrying amount capitalized in petroleum and natural gas assets is depleted in accordance with the Company's depletion policy. The Company reviews the obligation at each reporting date and revisions to the estimated timing of cash flows, discount rates and estimated costs will result in an increase or decrease to the obligations. Any difference between the actual costs incurred upon settlement of the obligation and recorded liability is recognized as an increase or reduction in income.

(e) Finance expenses

Finance expense may be comprised of interest expense on borrowings, acquisition related (transaction) costs, foreign exchange expenses and accretion of the discount on decommissioning obligations.

(f) Financial instruments

Financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, financial instruments are measured based on their classification as described below:

- Fair value through profit or loss: Financial instruments under this classification include risk management assets and liabilities.
- Amortized cost: Financial instruments under this classification include cash, accounts receivable, deposits, bank indebtedness, accounts payable and long term debt.

(g) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares are recognized as a reduction in share capital, net of any tax effects.

(h) Income taxes

The Company's income tax expense is comprised of current and deferred tax. Income tax expense is recognized through income or loss except to the extent that it relates to items recognized directly in equity, in which case the related income taxes are also recognized in equity.

Current tax is the expected tax payable on taxable income for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable income. Deferred tax liabilities are generally recognized for all taxable temporary differences. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which those deductible temporary differences can be utilized. Assessing the recoverability of deferred tax assets requires management to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in the jurisdictions of Alberta and Canada. The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered.

(i) Joint arrangements

A portion of the Company's exploration, development and production activities are conducted jointly with others through unincorporated joint operations. These financial statements reflect only the Company's proportionate interest of these joint operations and the proportionate share of the relevant revenue and related costs.

(j) Share-based compensation

Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the qualifying portion of share-based compensation expense directly attributable to the exploration and development activities of exploration and evaluation assets and petroleum and natural gas assets, with a corresponding decrease to share-based compensation expense. At the time the stock options or performance warrants are exercised, the issuance of common shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

For deferred share units ("DSUs") that can be settled in cash or equity at the option of the Company, the fair value of the DSUs is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus.

(k) Earnings per share

Earnings per share are presented for basic and diluted earnings. Basic per share information is computed by dividing the net income (loss) for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period. The weighted average number of shares for diluted earnings per share information is calculated using the treasury stock method whereby it is assumed that proceeds obtained upon exercise of performance warrants and stock options would be used to purchase common shares at the average market price during the period. The treasury stock method also assumes that the deemed proceeds related to unrecognized share-based payments expense are used to repurchase shares at the average market price during the period. Under the treasury stock method, stock options and share warrants have a dilutive effect only when the average market price of the common shares during the period exceeds the exercise price of the options or warrants (they are "in-the-money"). Exercise of in-the-money stock options and share warrants is assumed at the beginning of the year or date of issuance, if later. Should the Company have a loss for the period, stock options and share warrants would be anti-dilutive and therefore will have no effect on the determination of loss per share.

(l) Leases

At inception of a contract, the Company assesses whether a contract is, or contains a lease. A contract is, or contains 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. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether:

- the contract involves the use of an identified asset - this may be specified explicitly or implicitly, and should be physically distinct or represent substantially all of the capacity of a physically distinct asset. If the suppler has a substantive substitution right, the asset is not identified;
- the Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
- the Company has the right to direct the use of the asset. The Company has this right when it has the decision-making rights that are most relevant to changing how and for what purpose the asset is used is predetermined, the Company has the right to direct the use of the asset if either:
    - the Company has the right to operate the asset; or
    - the Company designed the asset in a way that predetermines how and for what purpose it will be used.

i) As a lessee

The Company recognizes a right-of-use ("ROU") asset and a lease liability at the lease commencement date. The ROU asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The ROU asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the ROU asset or the end of the lease term. The estimated useful lives of ROU assets are determined on the same basis as those of property and equipment. In addition, the ROU asset is periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the intrest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

(m) Government grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attaching to it, and that the grant will be received. Grants related to income are presented in the Consolidated Statement of Comprehensive Income and are deducted in reporting the related expense. Grants related to assets are presented in the Consolidated Balance Sheet by deducting the grant in arriving at the carrying amount of the asset or recognized as other income.

Carbon credits

Carbon credits that are held for sale in the ordinary course of business are recognized as inventory in the year credits are verified and are measured at the lower of cost or net realizable value. The cost of emission credits is determined at the market value of the credits in the year credits are verified.

Upon sale of the carbon credits, the carrying amount is derecognized from inventory on the Consolidated Balance Sheet, recording any gain or loss on the Statements of Net Income and Comprehensive Income.

(n) Business combinations

The acquisition method of accounting is used to account for acquisitions of entities and assets that meet the definition of a business under IFRS. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets acquired and liabilities and contingent liabilities assumed is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in profit or loss. Business combination associated transaction costs are expensed when incurred.

Within the IFRS Business Combinations guidance, there is an optional fair value concentration test. The concentration test is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an entity chooses not to apply the concentration test, or the test is failed, then the assessment focuses on the existence of a substantive process, and the acquisition is accounted for as a business combination. The cost of an acquisition that does not meet the definition of a business under IFRS and does not qualify as a business combination is measured as the fair value of the consideration given and liabilities incurred or assumed at the date of exchange. No goodwill arises on an asset acquisition and the cost of the assets acquired and liabilities assumed are allocated to the assets and liabilities on the basis of their relative fair values at the date of purchase. Asset acquisition associated transaction costs are capitalized as a cost of the acquisition.

(o) New standards and interpretations

In January 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* ("IAS 1"), to clarify its requirements for the presentation of liabilities as current or non-current in the statement of financial position. This will be effective on January 1, 2024.

In October 2022, the IASB issued amendments to IAS 1, which specify the classification and disclosure of a liability with covenants. This will be effective on January 1, 2024.

4. DETERMINATION OF FAIR VALUES

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Petroleum and natural gas properties and equipment and exploration and evaluation assets

The fair value of petroleum and natural gas properties and equipment is estimated for recognition in a business combination and for impairment testing. The fair value of petroleum and natural gas properties and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas properties and equipment and intangible exploration and evaluation assets is estimated with reference to the discounted cash flow expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. In certain instances, the estimate of fair value may also consider an evaluation of comparable asset transactions. The fair value less costs of disposal value used to determine the recoverable amount of the impaired petroleum and natural gas properties are classified as Level 3 fair value measurements. Refer to "Financial Instruments" section below for fair value hierarchy classifications.

Derivatives

The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options is based on option models that use published information with respect to volatility, prices, interest rates and counter-party credit risks.

Share-based payments

The fair value of employee share-based payments is measured using a Black-Scholes option-pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility in share price (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividend yield, risk-free interest rate (based on government bonds) and estimated forfeiture rate at each reporting date.

Financial Instruments

The Company's fair value measurements require disclosure about how the fair value was determined based on significant levels of inputs described in the following hierarchy:

- Level 1 - 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 pricing information on an ongoing basis.

- Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

- Level 3 - Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. The Company's risk management contracts are considered Level 2.

5. ACQUISITIONS

On March 14, 2022, Petrus completed the acquisition of certain oil and liquids rich natural gas weighted properties within its Ferrier core area from a privately owned limited partnership and its general partner. The acquired partnership was managed and directed by an officer and director of Petrus and two of Petrus' major shareholders owned or controlled, in aggregate, approximately 69.5% and 50% of the acquired partnership's units and shares, respectively.

Given the close proximity of the acquired properties to the Company's existing assets and infrastructure, the acquired properties are synergistic to existing operations and complementary to current development plans. The assets were acquired for share consideration of $15.2 million (10 million common shares of Petrus at $1.52 per share on closing date). The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in the transaction will be included in the Ferrier CGU. Asset acquisition transaction costs of $0.3 million were capitalized as a cost of the asset.

The amounts recognized on the date of acquisition to identifiable net assets were as follows:

$000s (except share and per share amounts)	
Net assets acquired:	
Cash & cash equivalents	434
Accounts receivable & other assets	496
Accounts payable & accrued liabilities	(406)
Property, plant and equipment	16,765
Decommissioning obligation	(2,089)
Net assets acquired	**15,200**
Purchase consideration:	
Common shares issued to partners	10,000,000
Price of Petrus common shares ($ per share) on close date	$1.52
Total purchase consideration	**15,200**

6. EXPLORATION AND EVALUATION ASSETS

The components of the Company's exploration and evaluation ("E&E") assets are as follows:

$000s	
Balance, December 31, 2021	**35,634**
Acquisitions	1,349
Exploration and evaluation expense	(421)
Capitalized G&A	295
Capitalized share-based compensation	122
Transfers to property, plant and equipment *(note 7)*	(2,142)
Balance, December 31, 2022	**34,837**
Additions	1,064
Exploration and evaluation expense	(4,706)
Capitalized G&A	284
Capitalized share-based compensation *(note 12)*	194
Transfers to property, plant and equipment *(note 7)*	(1,045)
Balance, December 31, 2023	**30,628**

During the year ended December 31, 2023, the Company incurred exploration and evaluation expense of $4.7 million which relates to expired and nearly expired undeveloped, non-core land (year ended December 31, 2022 – $0.4 million).

During the year ended December 31, 2023, the Company capitalized $0.3 million of general and administrative expenses ("G&A") (year ended December 31, 2022 – $0.3 million) and $0.2 million of non-cash share-based compensation directly attributable to exploration activities (year ended December 31, 2022 – $0.1 million).

During the year ended December 31, 2023, the Company transferred $1.0 million from E&E assets to PP&E assets, related to the Ferrier and North Ferrier Cash Generating Units ("CGUs").

During the year ended December 31, 2023, E&E costs of $0.8 million in the Kakwa area were written off and recorded as exploration expense, as the area is no longer in the Company's long-term development plans.

The Company did not identify any indicators of impairment or impairment reversals, related to its E&E assets, in any of its other CGUs at December 31, 2023.

7. PROPERTY, PLANT AND EQUIPMENT

The components of the Company's property, plant and equipment ("PP&E") assets are as follows:

$000s	Cost	Accumulated DD&A	Net book value
Balance, December 31, 2021	**852,834**	**(613,587)**	**239,247**
Additions	94,145	—	94,145
Property acquisitions	16,765	—	16,765
Property dispositions	(71)	—	(71)
Capitalized G&A	884	—	884
Capitalized share based compensation	367	—	367
Transfer from exploration and evaluation assets *(note 6)*	2,142	—	2,142
Depletion & depreciation	—	(33,277)	(33,277)
Increase in decommissioning expenses	(4,450)	—	(4,450)
Balance, December 31, 2022	**962,616**	**(646,864)**	**315,752**
Additions	85,220	—	85,220
Property acquisition *(note 5)*	50	—	50
Property dispositions	(150)	—	(150)
Capitalized G&A	852	—	852
Capitalized share-based compensation *(note 12)*	583	—	583
Transfers from exploration and evaluation assets *(note 6)*	1,045	—	1,045
Depletion & depreciation	—	(46,623)	(46,623)
Changes in decommissioning provision *(note 10)*	(1,626)	—	(1,626)
Balance, December 31, 2023	**1,048,590**	**(693,487)**	**355,103**

At December 31, 2023, estimated future development costs of $507.0 million (December 31, 2022 – $519.8 million) associated with the development of the Company's proved plus probable undeveloped reserves were included with the costs subject to depletion. During the year ended December 31, 2023, the Company capitalized $0.9 million of general and administrative expenses ("G&A") (year ended December 31, 2022 – $0.9 million) and non-cash share-based compensation of $0.6 million (year ended December 31, 2022 – $0.4 million), directly attributable to development activities.

During the year ended December 31, 2023, the Company transferred $1.0 million from E&E assets to PP&E assets, related to the Ferrier CGU.

At December 31, 2023, the carrying balance of the right of use asset was $0.3 million.

As at December 31, 2023, the book value of the Company's net assets was greater than its market capitalization. Together with the decline in near term natural gas forward prices, the Company considered these two factors combined as indicators of impairment and performed an impairment test on its Ferrier and Central Alberta CGUs considering estimated after-tax future cash flows based on proved developed producing reserves or proved and probable reserves and comparable transaction metrics.

For the Ferrier CGU, the recoverable amount exceeded the carrying value and therefore no impairment was recorded. The recoverable amount, a level 3 input on the fair value hierarchy (see note 2), was estimated at FVLCOD model based on proved plus and probable reserves and applying an after-tax discount rate of 12.5% on the estimated future cash flows.

For the Central Alberta CGU, the Company considered comparable transaction metrics as well as estimated after-tax future cash flows based on proved developed producing reserves in estimating the recoverable amount. Based on the analysis performed, the recoverable amount was determined to approximate its carrying value and therefore no impairment or impairment reversal was recorded.

The Company used the following forward commodity price assumptions in estimating future cash flows:

Year	Canadian Light Sweet 40 API $/Bbl	AECO $/MMbtu
2024	93.83	2.25
2025	95.50	3.35
2026	97.00	4.00
2027	98.94	4.08
2028	100.92	4.16
2029	102.94	4.24
2030	105.00	4.33
2031	107.10	4.42
2032	109.24	4.50
2033	111.42	4.59
2034	113.65	4.69

Escalation rate of 2.0% thereafter.

An increase of 1% in the discount rate applied would not result in an impairment for either CGU. A 5% decrease in oil and natural gas price forecasts, holding other assumptions constant, would also not result in any impairment for either CGU.

8. DEBT

At December 31, 2023, Petrus had two debt instruments outstanding; a reserve-based, secured operating revolving loan facility with an Alberta-based financial institution (the "Revolving Loan Facility" or "RLF") and a second lien secured term facility (the "Second Lien Facility").

Revolving Loan Facility
At December 31, 2023, the RLF was comprised of a $60.0 million operating facility payable on demand by the lender. The amount of the RLF is subject to a borrowing base review performed on a semi-annual basis by the lender, based primarily on reserves and commodity prices estimated by the lenders as well as other factors. During the fourth quarter of 2023, the Company's lender completed the semi-annual borrowing base redetermination and increased the borrowing limit from $45 million to $60 million. The next semi-annual review is due on May 31, 2024.

At December 31, 2023, the Company had a $0.7 million letter of credit outstanding against the RLF (December 31, 2022 – $0.6 million) and had drawn $24.2 million against the RLF (December 31, 2022 – $4.6 million).

Second Lien Facility
At December 31, 2023 the Company had $25.0 million outstanding on the $25 million Second Lien Facility. The Second Lien Facility is a three-year term facility (maturity date May 31, 2025 with an option to the borrower to extend by an additional two years) with a fixed interest rate of 11% per annum and can be repaid at the discretion of the Company after the first year. The Second Lien Facility is a related party transaction with a major shareholder who owns approximately 21% of the outstanding shares of the Company (see note 22). The total interest paid in 2023 to the major shareholder, related to the Second Lien facility, was $2.8 million.

Debt Settlement - Term Loan & Revolving Credit Facility
During 2022, the Company entered into agreements with new lenders to the Company, providing two new credit facilities, as described above, (the "New Credit Facilities") totaling $55 million. The New Credit Facilities, together with the net proceeds of the Company's $20 million rights offering, were used to repay in full all amounts owing under the Company's previous revolving credit facility (the "Revolving Credit Facility" or "RCF"). The New Credit Facilities closed in May 2022.

Financial Covenants
The Company's RLF is subject to certain financial covenants. The following definitions are used in the covenant calculations for the debt instrument:

Working Capital
Working Capital means Current Assets to Current Liabilities whereby Current Assets means on any date of determination, the current assets of Petrus that would, in accordance with IFRS, be classified as of that date as current assets plus any undrawn availability under the RLF, less any non-cash amount required to be included in current assets as the result of the application of IFRS including non-cash commodity and interest rate hedges assets and liabilities and whereby Current Liabilities means, on any date of determination, the liabilities of Petrus that would, in accordance with IFRS, be classified as of that date as current liabilities, excluding (a) non-cash obligations under IFRS including non-cash commodity and interest rate hedges assets and liabilities, and (b) the current portion of long-term debt.

Working Capital Ratio means the ratio of Current Assets to Current Liabilities as defined above, less any amounts outstanding under the Company's RLF.

The key financial covenants as at December 31, 2023 are summarized in the following table. At December 31, 2023 the Company is in compliance with all financial covenants.

Financial Covenant Description	Required Ratio	As at December 31, 2023
Working Capital Ratio	Over 1.0	1.5

9. LEASES

The Company's lease obligations are as follows:

$000s	
Balance, December 31, 2022	**603**
Finance expense	37
Lease payments	(277)
Balance, December 31, 2023	**363**

The Company's future commitments associated with its lease obligations are as follows:

$000s	As at December 31, 2023
Less than 1 year	277
1 to 3 years	92
Total lease payments	369
Amounts representing finance expense	(6)
Present value of lease obligation	363
Current portion of lease obligation	258
Non-current portion of lease obligation	105

10. DECOMMISSIONING OBLIGATION

The decommissioning liability was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The estimated future cash flows have been discounted using an average risk free rate of 3.05 percent and an inflation rate of 2.00 percent (3.31 percent and 3.00 percent, respectively, at December 31, 2022). Changes in estimates in 2022 and 2023 are due to the change in the risk free and inflation rates and changes in the estimated future cash flow to reclaim the wells and facilities. The Company has estimated the net present value of the decommissioning obligations to be $37.3 million as at December 31, 2023 ($39.0 million at December 31, 2022). The undiscounted, uninflated total future liability at December 31, 2023 is $44.3 million ($41.7 million at December 31, 2022). The payments are expected to be incurred over the operating lives of the assets.

The following table reconciles the decommissioning liability:

$000s	
Balance, December 31, 2021	**41,569**
Property acquisitions *(note 5)*	2,089
Property dispositions	(681)
Other adjustments	(441)
Liabilities incurred	1,231
Liabilities settled	(137)
Change in estimates	(5,681)
Accretion expense	1,066
Balance, December 31, 2022	**39,015**
Liabilities incurred	525
Liabilities settled	(1,374)
Change in estimates	(2,152)
Accretion expense	1,277
Balance, December 31, 2023	**37,291**

11. FINANCIAL RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility. The following table summarizes the financial derivative contracts Petrus had outstanding as at December 31, 2023:

Contract Period	Type	Total Daily Volume (GJ)	Average Price (CDN$/GJ)
Natural Gas Swaps			
Jan. 1, 2024 to Mar. 31, 2024	Fixed price	20,000	$4.14
Apr. 1, 2024 to Oct. 31, 2024	Fixed price	14,000	$3.06
Nov. 1, 2024 to Mar. 31, 2025	Fixed price	9,000	$3.73
Apr. 1, 2025 to Oct. 31, 2025	Fixed price	6,000	$3.14
Natural Gas Collars			
Apr. 1, 2024 to Oct. 31, 2024	Costless collar	1,000	$2.12-2.46
Nov. 1, 2024 to Mar 31, 2025	Costless collar	1,000	$3.25-4.12
Nov. 1, 2024 to Mar 31, 2025	Costless collar	1,000	$3.42-3.62
Apr. 1, 2025 to Oct. 31, 2025	Costless collar	1,000	$3.10-3.83
Apr. 1, 2025 to Oct. 31, 2025	Costless collar	1,000	$2.50-3.16
Nov. 1, 2025 to Mar. 31, 2026	Costless collar	1,000	$3.30-4.08

Contract Period	Type	Total Daily Volume (Bbl)	Average Price (CDN$/Bbl)
Crude Oil Swaps			
Jan. 1, 2024 to Mar. 31, 2024	Fixed price	300	$95.30
Jan. 1, 2024 to Jun. 30, 2024	Fixed price	1,300	$96.56
Jan. 1, 2024 to Dec. 31, 2024	Fixed price	500	$96.59
Jul. 1, 2024 to Sept. 30, 2024	Fixed price	100	$89.05
Jul. 1, 2024 to Dec. 31, 2024	Fixed price	400	$94.83
Jul. 1, 2024 to Jun. 30, 2025	Fixed price	100	$101.45
Oct. 1, 2024 to Dec. 31, 2024	Fixed price	100	$90.40
Jan. 1, 2025 to Mar. 31, 2025	Fixed price	200	$94.78
Jan. 1, 2025 to Jun. 30, 2025	Fixed price	400	$91.36
Jan. 1, 2025 to Dec. 31, 2025	Fixed price	100	$93.40
Jul. 1, 2025 to Sept. 30, 2025	Fixed price	100	$95.25

Risk management asset and liability:

$000s At December 31, 2023	**Asset**	**Liability**
Current commodity derivatives	8,770	396
Non-current commodity derivatives	1,685	—
	10,455	**396**
$000s At December 31, 2022		
Current commodity derivatives	4,502	—
Non-current commodity derivatives	619	—
	5,121	—

Earnings impact of realized and unrealized gains (losses) on financial derivatives:

$000s	**Year ended December 31, 2023**	**Year ended December 31, 2022**
Realized gain (loss) on financial derivatives	8,051	(1,601)
Unrealized gain on financial derivatives	4,938	7,609
Net gain (loss) on financial derivatives	**12,989**	**6,008**

During the year ended December 31, 2023, the Company realized a gain on risk management activities of $1.5 million (year ended December 31, 2022 - $6.0 million loss). There are no physical commodity contracts outstanding at December 31, 2023.

12. SHARE CAPITAL

Authorized
The authorized share capital consists of an unlimited number of common voting shares without par value and an unlimited number of preferred shares.

Issued and Outstanding

Common shares ($000s except number of shares)	Number of shares	Amount
Balance, December 31, 2021	**96,707,912**	**455,908**
Common shares issued for property acquisition	10,000,000	15,200
Common shares issues in rights offering	14,817,347	20,003
Common shares issued on exercise of stock options	1,713,269	1,427
Share issue costs	—	(297)
Balance, December 31, 2022	**123,238,528**	**492,241**
Common shares repurchased	(198,700)	(789)
Common shares issued on exercise of stock options	1,226,542	753
Balance, December 31, 2023	**124,266,370**	**492,205**

Dividends
On October 10, 2023, the Company declared a special dividend of $0.03 per common share totaling $3.7 million that was paid in November 2023. During the year ended December 31, 2023, the Company declared a monthly dividend of $0.01 per common share totaling $1.2 million, with the first payable in January 2024.

Normal Course Issuer Bid ("NCIB")
On June 21, 2023, the Company announced the approval of its NCIB by the Toronto Stock Exchange ("the TSX"). The 2023 NCIB allows the Company to purchase up to 6,192,426 common shares over a period of twelve months commencing June 28, 2023.

Purchases are made on the open market through the TSX or alternative platforms at the market price of such common shares. All common shares purchased under the NCIB are cancelled. The total cost paid, including commissions and fees, is first charged to share capital to the extent of the average carrying value of the Company’s common shares and the excess paid is recorded to retained earnings and any shortfall is recorded to contributed surplus.

During the year ended December 31, 2023, the Company repurchased 198,700 shares for cancellation at an average price of $1.42 per share.

Rights Offering
During the year ended December 31, 2022, the Company completed a rights offering (the “Offering”). Pursuant to the Offering, the Company issued 14.8 million common shares at $1.35 per share for aggregate gross proceeds to the Company of $20.0 million. The issuance costs were $0.3 million and the net proceeds of $19.6 million were utilized for debt repayment and towards working capital.

The Company entered into a standby purchase agreement with three investors (collectively, the "Stand-By Guarantors") who each own more than 20% of the outstanding shares of the Company. As a result of the exercise of the basic subscription privilege and additional subscription privilege by the holders of rights (including the Stand-By Guarantors), the Stand-By Guarantors did not acquire any Common Shares in connection with the Rights Offering pursuant to their stand-by commitments. The basic and additional subscriptions totaled 184% of the common shares of the Company available through the Rights Offering. The Company had approximately 121.7 million shares outstanding following the rights offering with the Stand-By Guarantors owning approximately 71% of the outstanding shares.

Property Acquisition
During the first quarter of 2022, the Company completed an asset acquisition. The assets were acquired for share consideration of $15.2 million (10 million common shares of Petrus at $1.52 per share on closing date).

SHARE-BASED COMPENSATION

Stock Options
The Company has a stock option plan in place whereby it may issue stock options to employees, consultants and directors of the Company. The aggregate number of shares that may be acquired upon exercise of all options granted pursuant to the plans shall, at any date or time of determination, be equal to ten percent (10%) of the number that is equal to (i) the number of the Company’s basic common shares then issued and outstanding; minus (ii) a number equal to five (5) times the number of common shares that are issuable upon exercise of the then outstanding Performance Warrants, if any, minus (iii) a number equal to fifty percent (50%) of the number of common shares that have previously been issued upon the exercise of Performance Warrants, if any.

At December 31, 2023, 8,616,900 (December 31, 2022 – 8,519,709) stock options were outstanding. The summary of stock option activity is presented below:

	Number of stock options	Weighted average exercise price
Balance, December 31, 2021	**5,562,549**	**$0.67**
Granted	4,677,500	$2.27
Expired	(7,071)	$0.74
Exercised	(1,713,269)	$0.60
Balance, December 31, 2022	**8,519,709**	**$1.56**
Granted	3,245,000	$1.67
Forfeited	(447,501)	$0.59
Expired	(1,207,500)	$2.12
Exercised	(1,492,808)	$0.61
Balance, December 31, 2023	**8,616,900**	**$1.74**
Exercisable, December 31, 2023	**1,155,225**	**$1.39**

The following table summarizes information about the stock options granted and currently outstanding:

Range of Exercise Price	**Stock Options Outstanding**		
	Number granted	**Weighted average exercise price**	**Weighted average remaining life (years)**
$0.24	25,135	$0.24	0.04
$0.53 - $0.75	1,777,594	$0.72	0.6
$0.89	546,672	$0.89	0.6
$1.37 - $1.78	3,098,333	$1.53	2.0
$2.09	530,000	$2.09	1.2
$2.25	1,607,500	$2.25	0.8
$2.81	1,031,666	$2.81	1.1
	8,616,900	**$1.74**	**1.2**

During the year ended December 31, 2023, the Company granted 3,245,000 options which vest equally over three years, and upon vesting, expire 30 business days thereafter. The weighted average fair value of each option granted during the year ended December 31, 2023 of $0.58 was estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions:

	2023	**2022**
Risk free interest rate	3.54% - 5.04%	2.46% - 4.34%
Expected life (years)	1.13 - 3.13	1.08 - 3.25
Estimated volatility of underlying common shares (%)	100% to 113%	100% to 113%
Estimated forfeiture rate	33%	33%
Expected dividend yield (%)	—%	—%

Petrus estimated the volatility of the underlying common shares by analyzing the Company's volatility as well as the volatility of peer group public companies with similar corporate structure, oil and gas assets and size.

Deferred Share Unit ("DSU") Plan

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. The aggregate number of shares that may be issued from treasury of Petrus pursuant to the plan shall not exceed: (i) five percent (5%) of the number of issued and outstanding common shares of the Company (on a non-diluted basis) at the date of issue; and (ii) ten percent (10%) of the number of issued and outstanding common shares of the Company (on a non-diluted basis) at the date of issue, less the aggregate number of common shares of the Company reserved for issuance under any other share compensation plan.

Each DSU entitles the participants to receive, at the Company's discretion, either shares of the Company or cash equal to the trading price of the equivalent number of shares of the Company. All DSUs granted vest and become payable upon retirement of the director.

The compensation expense was calculated using the fair value method based on the trading price of the Company's shares on the grant date. At December 31, 2023, 1,658,837 DSUs were issued and outstanding (December 31, 2022 – 1,618,702).

On each date that a dividend payment is made, holders of DSUs are credited with additional DSUs, which the number of additional DSUs is calculated by dividing the dividends that would have been paid to such holder if the DSUs held at the record date of the cash dividend had been common shares, by the fair market value of the common shares on the date on which the dividends are paid on the common shares.

The following table summarizes the Company's share-based compensation costs:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Expensed	1,863	1,141
Capitalized to exploration and evaluation assets	194	122
Capitalized to property, plant and equipment	583	367
Total share-based compensation	**2,640**	**1,630**

13. EARNINGS PER SHARE

Earnings per share amounts are calculated by dividing the net income for the period attributable to the common shareholders of the Company by the weighted average number of common shares outstanding during the period.

	Year ended December 31, 2023	Year ended December 31, 2022
Net income for the year ($000s)	**50,731**	**60,868**
Weighted average number of common shares – basic (000s)	123,469	115,189
Weighted average number of common shares – diluted (000s)	126,436	119,525
Net income per common share – basic	**$0.41**	**$0.53**
Net income per common share – diluted	**$0.40**	**$0.51**

In computing diluted earnings per share for the year ended December 31, 2023, 8,616,900 outstanding stock options and 1,658,837 DSUs were considered (December 31, 2022 – 8,519,709 and 1,618,702 respectively). There were 7,601,659 stock options that were anti-dilutive as the exercise price was higher than the average share price during the year ended December 31, 2023.

14. OPERATING EXPENSES

The Company's operating expenses consisted of the following expenditures:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Fixed and variable operating expenses	19,833	16,954
Processing, gathering and compression charges	5,068	4,853
Total gross operating expenses	**24,901**	**21,807**
Overhead recoveries	(1,396)	(1,142)
Total net operating expenses	**23,505**	**20,665**

15. GENERAL AND ADMINISTRATIVE EXPENSES

The Company's general and administrative expenses consisted of the following expenditures:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Gross general and administrative expenses	7,137	6,715
Capitalized general and administrative expenses	(1,136)	(1,179)
Overhead recoveries	(1,818)	(2,147)
General and administrative expenses	**4,183**	**3,389**

16. FINANCIAL INSTRUMENTS

Risks associated with financial instruments

Credit risk
The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risk. Concentration of credit risk is mitigated by marketing the majority of the Company's production to reputable and financially sound purchasers under normal industry sale and payment terms. As is common in the petroleum and natural gas industry in western Canada, Petrus' receivables relating to the sale of petroleum and natural gas are received on or about the 25th day of the following month. Of the $17.3 million of accounts receivable outstanding

at December 31, 2023 (December 31, 2022 – $22.2 million), $5.8 million is owed from 2 parties (December 31, 2022 – $15.3 million from 2 parties), and the balances were received subsequent to December 31, 2023. At December 31, 2023, the Company had an allowance for doubtful accounts of $0.1 million (December 31, 2022 – $0.1 million). The Company considers accounts receivable outstanding past 120 days to be 'past due'. At December 31, 2023, 99.9% of Petrus' accounts receivable were aged less than 120 days and 0.1% of Petrus' accounts receivable were aged greater than 120 days. The Company does not anticipate any material collection issues.

The Company's risk management assets and cash are with chartered Canadian banks and the Company does not consider these assets to carry material credit risk.

Liquidity risk
At December 31, 2023, the Company had a $60.0 million RLF, of which $24.4 million was drawn (December 31, 2022 – $4.6 million). For the year ended December 31, 2023, the Company generated cash flow from operating activities of $74.4 million.

The following are the contractual maturities of financial liabilities as at December 31, 2023:

$000s	Total	< 1 year	1-5 years
Accounts payable and accrued liabilities	34,003	34,003	—
Risk management liability	396	396	—
Bank indebtedness	228	228	—
Revolving loan facility	26,520	26,520	—
Lease obligations (discounted)	363	258	105
Long term debt	27,984	2,313	25,671
Total	**89,494**	**63,718**	**25,776**

Interest rate risk
Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company's cash, bank indebtedness and accounts receivable are not exposed to significant interest rate risk. The RLF is exposed to interest rate cash flow risk as the instrument is priced on a floating interest rate subject to fluctuations in market interest rates. The remainder of Petrus' financial assets and liabilities are not exposed to interest rate risk. A 1% increase in the Canadian prime interest rate during the year ended December 31, 2023 would have decreased net income by approximately $0.1 million, which relates to interest expense on the average outstanding RLF, assuming that all other variables remain constant (December 31, 2022 – $0.3 million). A 1% decrease in the Canadian prime interest rate during the year would result in an opposite impact on net income for 2022 and 2021.

Commodity price risk
Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. A significant change in commodity prices can materially impact the Company's borrowing base limit under its Revolving Credit Facility and may reduce the Company's ability to raise capital. Commodity prices for petroleum and natural gas are not only influenced by Canadian and United States demand, but also by world events that dictate the levels of supply and demand.

The Company manages the risks associated with changes in commodity prices by entering into a variety of financial derivative contracts (see note 11). The Company assesses the effects of movement in commodity prices on net loss. When assessing the potential impact of these commodity price changes, the Company believes a $5/CDN WTI/bbl change in the price of oil and a $0.25/GJ change in the price of natural gas are reasonable measures.

As at December 31, 2023, it was estimated that a $0.25/GJ decrease in the price of natural gas would have increased net income by $2.1 million (December 31, 2022 – $1.4 million). An opposite change in commodity prices would result in an opposite impact on net income for the period. As at December 31, 2023, it was estimated that a $5.00/CDN WTI/bbl decrease in the price of oil would have increased net income by $3.6 million (December 31, 2022 – $3.1 million). An opposite change in commodity prices would result in an opposite impact on net income for the period.

17. CAPITAL MANAGEMENT

The Company's general capital management policy is to maintain a sufficient capital base in order to manage its business to enable the Company to increase the value of its assets and therefore its underlying share value. In the management of capital, the Company includes share capital and total net debt, which is made up of debt and working capital (current assets less current liabilities). The Company manages its capital structure and makes adjustments in light of economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, Petrus may issue new equity, increase or decrease debt, adjust capital expenditures and acquire or dispose of assets.

18. FINANCE EXPENSES

The components of finance expenses are as follows:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Cash:		
Interest and finance fees	4,205	2,175
Finance fees	596	993
Foreign exchange	—	3
Total cash finance expenses	4,801	3,171
Non-cash:		
Deferred financing costs	376	430
Non-cash term loan interest payment-in-kind	—	—
Accretion on decommissioning obligations *(note 10)*	1,277	1,066
Total non-cash finance expenses	1,653	1,496
Total finance expenses	**6,454**	**4,667**

19. SUPPLEMENTAL CASH FLOW INFORMATION

The following table reconciles the changes in non-cash working capital as disclosed in the statements of cash flows:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Source (use) in non-cash working capital:		
Deposits and prepaid expenses	(505)	(362)
Transaction costs on debt	60	(518)
Inventory and others	(630)	(515)
Accounts receivable	4,966	(12,515)
Accounts payable and accrued liabilities	(11,188)	25,501
	(7,297)	**11,591**
Operating activities	(3,654)	12,891
Investing activities	(3,643)	(1,300)

The following table reconciles the changes in liability resulting from financing activities:

$000s	Bank Indebtedness	Revolving Credit Facility	Term Loan	Total Liabilities from Financing Activities
Balance, December 31, 2022	**658**	**3,949**	**25,000**	**29,607**
Cash flows	(450)	20,622	—	20,172
Non-cash changes	—	(396)	—	(396)
Balance, December 31, 2023	**208**	**24,175**	**25,000**	**49,383**

20. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The commitments for which the Company is responsible are as follows:

$000s	Total	< 1 year	1-5 years	> 5 years
Firm service transportation	9,386	2,799	6,587	—

CONTINGENCIES

In the normal course of Petrus' operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty. Petrus does not anticipate that these claims will have a material impact on its financial position.

21. REVENUE

The following table presents Petrus' oil and natural gas revenue disaggregated by product type:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Oil and condensate sales	55,676	59,348
Natural gas sales	46,972	67,025
Natural gas liquids sales	22,603	25,267
Royalty revenue	354	710
Oil and natural gas sales	**125,605**	**152,350**
Royalty expense	(17,255)	(24,161)
Gain (loss) on risk management activities	1,522	(6,029)
Net revenue	**109,872**	**122,160**

22. RELATED PARTY TRANSACTIONS

The Company considers its directors and officers to be key management personnel. The following table outlines transactions with key management personnel:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Salaries, consulting fees, benefits and director fees, gross	1,348	1,245
Share based compensation, gross	1,135	445
	2,483	**1,690**

During the year ended December 31, 2022, the Company completed its debt restructuring transactions, which included the Second Lien Facility in the form of a promissory note held by a major shareholder, owning approximately 21% of the outstanding shares of the Company (see note 8).

During the year ended December 31, 2022, the Company closed an asset acquisition that was considered a related party transaction (see note 5).

During the year ended December 31, 2022, the Company entered into a standby purchase agreement with three investors (collectively, the "Stand-By Guarantors") who each own more than 20% of the outstanding shares of the Company. The Company entered into a standby purchase agreement with each of Don Gray, Stuart Gray and Glen Gray (collectively, the "Stand-By Guarantors"). The Rights Offering was oversubscribed by 84% and as a result, the Stand-By Guarantors did not acquire any Common Shares in connection with the Rights Offering pursuant to their stand-by commitments. The Company had approximately 121.7 million share outstanding following the Rights Offering with the Stand-By Guarantors owning approximately 71% of the outstanding shares.

23. DEFERRED INCOME TAXES

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Income before taxes	31,110	60,868
Combined federal and provincial tax rate	23.0 %	23.0 %
Computed “expected” tax recovery	7,155	14,000
Increase/(decrease) in taxes resulting from:		
Permanent items	1	1
Share based payments	429	306
Share issuance costs	(20)	(80)
True up and other		1,059
Unrecognized deferred income tax asset	(27,186)	(15,286)
Deferred tax recovery	**(19,621)**	**—**
Effective tax rate	— %	— %

The components of the Company's deferred tax position at December 31, 2023 and 2022 are as follows:

$000s	2023	2022
Exploration and evaluation assets and property, plant and equipment	37,305	27,439
Asset retirement obligations	(8,577)	(8,661)
Share issuance costs	(55)	(184)
Non capital loss carry-forwards	(50,608)	(19,771)
Unrealized hedging loss	2,314	1,178
Deferred tax asset	**(19,621)**	—

The company has unrecognized deductible temporary differences in the form of non-capital loss carry-forward of approximately nil (2022 - $120.7 million). The Company had non-capital losses of approximately $221.4 million (2022 – $206.7 million) which may be applied against future income for Canadian tax purposes. These non-capital losses expire in 2033 and onwards.

24. OTHER ASSETS

The components of the Company's other assets at December 31, 2023 and 2022 are as follows:

$000s	2023	2022
Oil and gas equipment inventory	—	578
Carbon credits	1,842	619
Other assets	**1,842**	**1,197**

25. DEPOSITS AND PREPAID EXPENSES

The components of the Company's deposits and prepaid expenses as at December 31, 2023 and 2022 are as follows:

$000s	2023	2022
Prepaid interest and bank fees	169	229
Prepaid insurance	202	414
Prepaid operating expenses	19	19
Prepaid software	154	172
Deposits	1,992	1,028
Deposits and prepaid expenses	**2,536**	**1,862**

26. OTHER INCOME

The following table presents Petrus' other income by category:

$000s	Year ended December 31, 2023	Year ended December 31, 2022
Carbon credits	1,223	619
Government grant for decommissioning activities	—	441
Other	79	291
Other income	**1,302**	**1,351**

CORPORATE INFORMATION

OFFICERS & VICE PRESIDENTS

Ken Gray, P.Eng
President and
Chief Executive Officer

Mathew Wong, CPA, CFA, CPA (WA, USA)
Chief Financial Officer

Matt Skanderup
Chief Operating Officer

Lindsay Hatcher
Vice President, Commercial & Corporate Development

DIRECTORS

Don T. Gray
Chairman
Scottsdale, Arizona

Ken Gray
Calgary, Alberta

Patrick Arnell
Calgary, Alberta

Donald Cormack
Calgary, Alberta

Peter Verburg
Calgary, Alberta

SOLICITOR

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITOR
Price Waterhouse Coopers (PwC)
Chartered Professional Accountants
Calgary, Alberta

INDEPENDENT RESERVE EVALUATORS
InSite Petroleum Consultants Ltd.
Calgary, Alberta

BANKERS
ATB Financial
Calgary, Alberta

TRANSFER AGENT
Odyssey Trust Company
Calgary, Alberta

HEAD OFFICE
2400, 240 – 4th Avenue S.W.
Calgary, Alberta T2P 4H4
Phone: 403-984-9014
Fax: 403-984-2717

WEBSITE
www.petrusresources.com