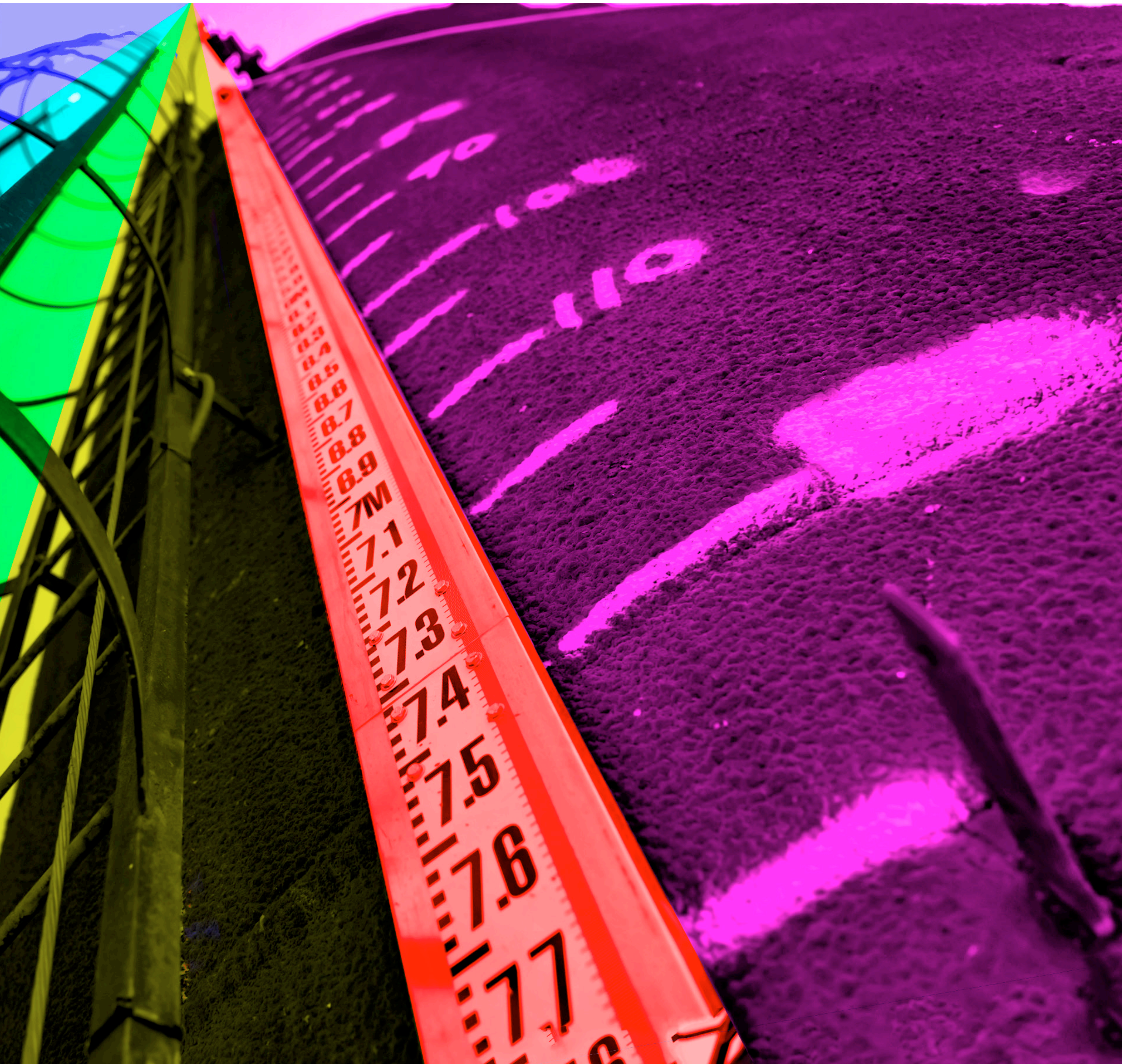
2022 ANNUAL RESULTS

PERPETUAL
ENERGY



ADVISORIES

This letter to shareholders, 2022 annual highlights and Annual Results report refer to certain non-GAAP measures and metrics commonly used in the oil and natural gas industry and provides forward-looking information and statements. Further detailed information regarding these measures is provided in this Annual Results report in "Management's Discussion and Analysis – NON-GAAP MEASURES" on pages 21 to 23, "Management's Discussion and Analysis – FORWARD-LOOKING INFORMATION AND STATEMENTS" on page 25.

In addition to the disclosure set out in the Company's Management's Discussion and Analysis for the period ended December 31, 2022, we provide certain supplementary disclosure throughout this Annual Results report in respect of certain specified financial measures (as such term is defined in National Instrument 51-112 –*Non-GAAP and Other Financial Measures*) and in respect of certain oil and gas metrics.

TO SHAREHOLDERS

In 2022, Perpetual Energy Inc. ("Perpetual" or "the Company") delivered strong operational and financial performance, largely propelled by the improved liquidity and cost structure unlocked by the Rubellite transaction in 2021. Perpetual was well positioned to capitalize on the surge in North American natural gas prices experienced in the second half of 2022 as natural gas shortages in Europe and energy security concerns buoyed North American markets. By investing alongside its partner in the continued development of the Wilrich liquids-rich natural gas resource play at Edson, production was restored to optimize the existing infrastructure. The Company also executed a very successful five well drilling program at Mannville utilizing multi-lateral horizontal drilling technology, applying learnings from its operations in the Clearwater play to the Sparky Formation. Strong performance combined with rising global oil prices that continued to rebound from their lows at the start of the COVID pandemic in the spring of 2020 to deliver attractive economic returns from these heavy oil focused investments.

With a healthy balance sheet, Perpetual's business plan remains focused on growing production, reserves, funds flow and value. The Company's strategic priorities for 2023 are to:

1. Maximize Funds Flow and Value of Edson;
2. Maximize Funds Flow and Value of Mannville;
3. Re-Ignite Active Exploration Program for Tight Oil and Gas;
4. Advance Technology-Driven Diversifying New Ventures; and
5. Further Strengthen Balance Sheet and Manage Risk

Perpetual is pleased to welcome Steve Spence to the Board of Directors. We look forward to the technical expertise and guidance that Steve will bring to the Company's exploration and development activities and strategic initiatives. The Board of Directors and Management truly appreciate the commitment of our talented team and the support of our shareholders, service providers and many stakeholders.

Susan Riddell Rose

SUE RIDDELL ROSE
President and Chief Executive Officer

March 13, 2023

2022 FINANCIAL AND OPERATING HIGHLIGHTS

- Production for full year 2022 averaged 6,486 boe/d (20% heavy crude oil and NGL), an increase of 20% from 2021.

- Production growth was driven by successful core area drilling programs. At East Edson, four (2.0 net) wells were drilled and placed on production in the fourth quarter of 2021 and six (3.0 net) Wilrich wells were drilled and placed on production during the second half of 2022. Due to high gathering line pressures, one (0.5 net) Notikewin well drilled, completed and tied-in in 2022 was placed on production in the first quarter of 2023. At Mannville, two (2.0 net) horizontal multi-lateral heavy oil wells were drilled and placed on production late in the first quarter of 2022 and three (3.0 net) additional multi-lateral heavy oil wells were on production in the third quarter of 2022.

- Full year 2022 exploration and development capital spending totaled $31.9 million. The Company also spent $1.6 million on Crown land purchases at East Edson with its 50% joint interest partner. In addition, close to $1.5 million was spent on asset retirement obligations ("ARO") during the year to abandon wells that had reached their end of life and execute surface lease reclamation activities.

- Revenue net of $4.6 million in realized losses on risk management contracts for 2022 was $105.1 million, close to double the $56.0 million of revenue in 2021 due to the combined effect of higher production and stronger realized commodity prices.

- Cash costs were $34.4 million ($14.55/boe), up 23% from 2021 ($2021 - $27.9 million; $14.19/boe) as inflationary pressures were somewhat offset by efficiency gains related to higher production levels across a largely fixed operating cost base.

- Adjusted funds flow recorded for 2022 was $48.5 million ($0.75 per share), up $31.7 million (189%) from $16.7 million ($0.27/share) in 2021. On a unit-of-production basis, adjusted funds flow per boe for 2022 was $20.48/boe, a 141% increase from the prior year period of $8.51/boe. Net cash flows from operating activities for 2022 were $37.8 million while and net income of $44.4 million ($0.69/share) was recorded for the year.

- As year end 2022, net debt[1] was $56.3 million, down 4% from December 31, 2021, as adjusted funds flow exceeded capital expenditures and payments related to the retained East Edson royalty obligation during 2022 which were in place until December 31, 2022. Perpetual's balance sheet was materially improved with the repayment of the majority of the second lien term loan and bank debt with proceeds from the Rubellite Transaction in 2021. Strengthening commodity prices and production growth in 2022 drove further improvements to the balance sheet at year end 2022, with a net debt to trailing twelve months adjusted funds flow ratio[1] of 1.2 times.

- Perpetual had available liquidity[1] at December 31, 2022 of $13.9 million, comprised of the $30.0 million borrowing limit of Perpetual's first lien credit facility, less current borrowings and letters of credit of $14.9 million and $1.2 million, respectively.

(1) Non-GAAP measure, capital measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within these annual results.

FINANCIAL AND OPERATING HIGHLIGHTS

($Cdn thousands except volume and per share amounts)	Three Months Ended December 31, 2022	2021	Change	Twelve Months Ended December 31, 2022	2021	Change
Financial						
Oil and natural gas revenue	**28,579**	21,449	33 %	**109,687**	60,814	80 %
Net income (loss)	**9,264**	5,669	63 %	**28,503**	81,121	(65)%
Per share – basic(2)	**0.14**	0.09	56 %	**0.69**	1.29	(47)%
Per share – diluted(2)	**0.12**	0.08	50 %	**0.59**	1.16	(49)%
Cash flow from operating activities	**8,749**	1,624	439 %	**37,830**	12,815	195 %
Adjusted funds flow(1)	**14,207**	8,585	65 %	**48,471**	16,746	189 %
Per share(3)	**0.22**	0.13	66 %	**0.74**	0.27	174 %
Total assets	**218,273**	178,851	22 %	**218,273**	178,851	22 %
Revolving bank debt	**14,909**	2,487	499 %	**14,909**	2,487	499 %
Term loan, principal amount	**2,671**	2,671	— %	**2,671**	2,671	— %
Other liability (undiscounted)	**3,342**	1,387	141 %	**3,342**	1,387	141 %
Senior Notes, principal amount	**35,647**	36,582	(3)%	**35,647**	36,582	(3)%
Adjusted working capital (surplus) deficiency(1)	**(220)**	16,143	(101)%	**(220)**	16,143	(101)%
Net debt(1)	**56,349**	59,270	(5)%	**56,349**	59,270	(5)%
Capital expenditures						
Exploration and development(1)	**115**	7,558	(98)%	**31,909**	19,062	67 %
Net proceeds on dispositions	**—**	53,407	(100)%	**—**	49,549	(100)%
Net capital expenditures	**115**	60,965	(100)%	**31,909**	68,611	(53)%
Common shares outstanding (thousands)(4)						
End of period	**65,944**	63,567	4 %	**65,944**	63,567	4 %
Weighted average – basic	**65,883**	63,853	3 %	**64,448**	62,969	2 %
Weighted average – diluted	**75,090**	70,873	6 %	**74,798**	69,989	7 %
Operating						
Daily average production						
Conventional natural gas (*MMcf/d*)	**33.0**	31.5	5 %	**31.0**	24.6	26 %
Heavy crude oil (*bbl/d*)	**1,126**	714	58 %	**898**	963	(7)%
NGL (*bbl/d*)	**508**	395	29 %	**416**	331	26 %
Total (boe/d)(5)	**7,138**	6,359	12 %	**6,486**	5,389	20 %
Average realized prices						
Realized natural gas price (*$/Mcf*)(1)	**5.78**	4.80	20 %	**5.90**	3.15	87 %
Realized oil price (*$/bbl*)(1)	**71.14**	73.96	(4)%	**90.15**	57.36	57 %
Realized NGL price (*$/bbl*)(1)	**78.36**	73.44	7 %	**88.05**	63.24	39 %
Wells drilled – gross (net)						
Conventional natural gas	**-/-**	4.0/2.0		**7 (3.5)**	9.0/4.5	
Heavy crude oil	**-/-**	- (-)		**5 (5.0)**	5.0/4.0	
Total	**-/-**	4.0/2.0	(100)%	**12 (8.5)**	14.0/8.5	(14)%

(1) Non-GAAP measure, capital management measure, non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within these annual results.
(2) Based on weighted average basic common shares outstanding for the period.
(3) Adjusted funds flows divided by the Company's shares outstanding.
(4) Shares outstanding are net of shares held in trust (2022 – 1.3 million; 2021 – 0.5 million).
(5) Please refer to "Glossary – Volume conversions" on page 23.

YEAR-END 2022 RESERVES

Reserve Highlights

Reserve additions offset production resulting in a nominal increase in total Company proved plus probable reserves year-over-year of 0.4 Mboe. Perpetual's proved plus probable reserves at year-end 2022 are 31.6 MMboe, comprised of 20% crude oil and NGL (2021 – 31.6 MMboe; 19% crude oil and NGL).

The quality of Perpetual's assets and positive momentum to drive operational and execution excellence in its core operating areas are demonstrated by the highlights below:

- Total proved reserves were 21.2 MMboe at year-end 2022, representing 67% of the Company's proved plus probable reserves (2021 – 71%).
- Proved plus probable producing reserves were 15.7 MMboe at December 31, 2022, representing 50% of total proved plus probable reserves (2021 – 15.2 MMboe; 48%).
- Total proved plus probable reserves in the Mannville area increased by 16% excluding production. Increases in reserves are largely due to the 2022 Mannville Heavy Oil multi-lateral drill program, gas recompletions, and economic factors.
- Perpetual's total exploration and development capital spending of $30.2 million (excluding $1.7 million of land and corporate capital), resulted in proved developed producing reserves additions of 2.46 MMboe, for finding and development costs[1] of $12.28/boe. Based on 2022 operating netbacks of $29.11/boe, the proved developed producing recycle ratio[1] is 2.4 times. Additions on a proved plus probable producing basis were 2.81 MMboe, for a finding and development cost[1] of $10.76/boe and a recycle ratio[1] of 2.7 times.
- Based on the three consultant average price (McDaniel, GLJ, Sproule) forecasts (the "Consultant Average Price Forecast") used by McDaniel, the net present value ("NPV") of Perpetual's total proved plus probable reserves (discounted at 10%) before income tax, was $302.0 million (2021 – $230.5 million). The increase related primarily to the material increase in the independent reserve evaluators' forecast for natural gas, crude oil and NGL prices at year-end 2022 as compared to the prior year.
- All abandonment, decommissioning and reclamation obligations are included in the reserve report, consistent with year-end 2021. All reserve well decommissioning obligations as well as the additional costs expected to be incurred to abandon and reclaim non-reserve wells, facilities and pipelines are included.
- Based on the Consultant Average Price Forecast, Perpetual's reserve-based net asset value ("NAV")[1] (discounted at 10%) at year-end 2022 is estimated at $250.1 million ($3.80 per share) as compared to $177.6 million ($2.79 per share) at year-end 2021.

(1) Non-GAAP measure and ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within these annual results for an explanation of composition.

Reserves Disclosure

Working interest reserves included herein refer to working interest reserves before royalty deductions. Reserves information is based on an independent reserves evaluation report prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2022 (the "McDaniel Report"), and has been prepared in accordance with National Instrument 51-101 ("NI 51-101") using the Consultant Average Price Forecast. Complete NI 51-101 reserves disclosure including after-tax reserve values, reserves by major property and abandonment costs will be included in Perpetual's Annual Information Form ("AIF"), which, when filed, will be available on the Company's website at www.perpetualenergyinc.com and SEDAR at www.sedar.com. Perpetual's reserves at December 31, 2022 are summarized below:

Working Interest Reserves at December 31, 2022[1]

	Light and Medium Crude Oil *(Mbbl)*	Heavy Oil *(Mbbl)*	Conventional Natural Gas *(MMcf)*	Natural Gas Liquids *(Mbbl)*	Oil Equivalent *(Mboe)*
Proved Producing	10	1,931	60,665	839	12,891
Proved Non-Producing	—	249	782	12	391
Proved Undeveloped	—	679	39,887	630	7,957
Total Proved	**10**	**2,859**	**101,333**	**1,480**	**21,238**
Probable Producing	—	489	12,596	179	2,767
Probable Non-Producing	—	58	3,978	42	763
Probable Undeveloped	—	581	34,395	542	6,856
Total Probable	**—**	**1,128**	**50,969**	**763**	**10,386**
Total Proved plus Probable	**10**	**3,987**	**152,302**	**2,244**	**31,625**

(1) May not add due to rounding.

Reserves Reconciliation

Working Interest Reserves(1)

Barrels of Oil Equivalent (*Mboe*)	**Proved**	**Probable**	**Proved and Probable**
Opening Balance, December 31, 2021	22,301	9,273	31,574
Extensions and Improved Recovery	1,784	(243)	1,540
Discoveries	—	—	—
Technical Revisions	(2,383)	(1,407)	(3,790)
Acquisitions	751	2,524	3,275
Dispositions	—	—	—
Production	(2,365)	—	(2,365)
Economic Factors	1,151	239	1,389
Closing Balance, December 31, 2022	**21,238**	**10,386**	**31,625**

(1) May not add due to rounding.

Extensions and improved recoveries relate to the booking of 2 (1.0 net) Wilrich undeveloped locations in the southern portion of the East Edson property, 1 (0.5 net) 2022 Notikewin drill at East Edson, and development of 2 (2.0 net) unbooked Mannville Heavy Oil locations through the 2022 multi-lateral drilling program.

The East Edson property recorded a negative technical revision in the conventional natural gas and natural gas liquids categories due to a length adjustment of the type curve for 9 (4.2 net) undeveloped locations and updated type curve analysis on an additional 12 (5.7 net) undeveloped locations. The 2022 East Edson Wilrich drilling program delivered as expected on four of the six (2.0 net) previously booked Wilrich locations. The remaining two (1.0 net) 2022 East Edson Wilrich locations have underperformed expectations and contributed to a negative technical revision for the property. A review of the operational challenges and marginal economics of the Panny field in the Eastern District was conducted. The review resulted in a de-recognition of proven non-producing reserves which contributed to the negative conventional natural gas technical revision.

Lands acquired in East Edson area during 2022 added 7 (3.4 net) additional future drilling locations that were recognized as proved and probable undeveloped reserves.

Economic factors restored a portion of the technical revision due to the current reconciliation methodology. When the year end 2022 forecasts are evaluated at the Jan 1, 2022 Consultant Average price forecast, a portion of the forecast future production and reserves are terminated prematurely. The truncated reserves are then assigned to economics factors when evaluated at the Jan 1, 2023 Consultant Average price forecast.

The table below summarizes the future development capital ("FDC") estimated by McDaniel by play type to bring proved plus probable non-producing and undeveloped reserves to production.

Future Development Capital(1)

($ millions)	**2023**	**2024**	**2025**	**2026**	**2027**	**Remainder**	**Total**
Eastern Alberta Shallow Gas	0.0	0.3	0.3	0.3	0.0	0.0	0.9
Mannville Heavy Oil	2.3	4.5	5.2	5.8	0.0	0.0	17.8
East Edson Wilrich	17.7	19.9	17.2	17.9	12.4	0.8	85.9
Total	**20.0**	**24.7**	**22.8**	**23.9**	**12.4**	**0.8**	**104.6**

(1) May not add due to rounding.

The McDaniel Report estimates that FDC of $104.6 million will be required over the life of the Company's proved plus probable reserves. Proved plus probable reserve forecast FDC increased by $29.3 million (39%) from $75.3 million at December 31, 2021.

FDC for the East Edson property increased by $16.0 million in the proved category and $31.8 million in the proved and probable category and is attributable to the increased number of undeveloped locations as well as increased per well costs. At year end 2022, proved plus probable locations for 30 (14.1 net) horizontal conventional natural gas wells targeting the Wilrich at East Edson is up from 27 (12.7 net) at year end 2021.

At the Mannville property, 13 (13.0 net) horizontal heavy crude oil wells are booked as undeveloped, down from 16 (16.0 net) at year end 2021. Future capital costs also include recompletions of 14 (14.0 net) conventional natural gas wells included in Perpetual's proved plus probable reserves.

RESERVE LIFE INDEX

Perpetual's proved plus probable reserves to production ratio, also referred to as reserve life index ("RLI"), was 12.5 years at year-end 2022, while the proved RLI was 8.8 years, based upon the 2022 production estimates in the McDaniel Report. The following table summarizes Perpetual's historical calculated RLI.

Reserve Life Index(1)

Year-end	2022	2021	2020	2019	2018
Total Proved	8.8	9.1	10.9	13.4	13.1
Total Proved plus Probable	12.5	12.2	14.5	21.5	19.9

(1) Calculated as year-end reserves divided by year one production estimate from the McDaniel Report.

NET PRESENT VALUE OF RESERVES SUMMARY

Perpetual's heavy crude oil, conventional natural gas, and NGL reserves were evaluated by McDaniel using the Consultant Average Price Forecast effective January 1, 2023 and include the forecasted impact of the Company's market diversification contract, but prior to provision for financial oil and natural gas price hedges, foreign exchange contracts, income taxes, interest, debt service charges and general and administrative expenses. The following table summarizes the NPV of future revenue from reserves at December 31, 2022, assuming various discount rates:

NPV of Reserves, before income tax(1)(2)(3)

		Discounted at				
($ millions except as noted)	**Undiscounted**	**5%**	**10%**	**15%**	**20%**	**Unit Value Discounted at 10%/Year (*$/boe*)(4)**
Proved Producing	174	152	132	118	107	12.91
Proved Non-Producing	11	9	7	6	5	20.09
Proved Undeveloped	132	91	66	50	39	9.31
Total Proved	**317**	**251**	**206**	**174**	**151**	**11.61**
Probable Producing	61	40	28	21	17	11.86
Probable Non-Producing	11	6	4	3	2	6.53
Probable Undeveloped	154	95	64	46	35	10.89
Total Probable	**227**	**141**	**96**	**71**	**55**	**10.84**
Total Proved plus Probable	**543**	**392**	**302**	**245**	**206**	**11.35**

(1) January 1, 2023 Consultant Average price forecast.

(2) Inclusive of the East Edson royalty obligation, carbon tax, asset retirement obligations for sites not assigned reserves, and natural gas market diversification contracts.

(3) May not add due to rounding.

(4) The unit values are based on net reserve volumes.

McDaniel's NPV10 estimate of Perpetual's total proved plus probable reserves at year-end 2022 was $302.0 million, up 31% from $230.5 million at year-end 2021. The increase related primarily to the material increase in the independent reserve evaluators' forecast for crude oil prices at year-end 2022 as compared to the prior year. At a 10% discount factor, total proved reserves account for 68% (2021 – 68%) of the proved plus probable value. Proved plus probable producing reserves represent 53% (2021 – 47%) of the total proved plus probable value (discounted at 10%) as obligations for non-producing wells, facilities and pipelines, cabon tax, and forecast corporate marketing adjustments reduce the value of the developed producing reserves.

FAIR MARKET VALUE OF UNDEVELOPED LAND

Perpetual held 163,953 net undeveloped acres of land as at December 31, 2022, including 84,002 net undeveloped acres of oil sands leases. Undeveloped acres refers to land where there are not any existing wells within the rights associated with those lands and includes 49,765 net acres of undeveloped land assigned value by an independent third party at year end 2022. The estimate of the fair market value of the Company's undeveloped acreage was prepared by Seaton-Jordan & Associates Ltd. ("Seaton-Jordan") and is based on past Crown land sale activity, adjusted for tenure and other considerations. No undeveloped land value was assigned where proved and probable undeveloped reserves have been booked. The fair market value of Perpetual's undeveloped land at year-end 2022 is estimated by Seaton Jordan at $4.4 million.

NET ASSET VALUE

The following NAV table shows what is normally referred to as a "produce-out" NAV calculation under which the Company's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of Perpetual's shares. The calculations below do not reflect the value of the Company's prospect inventory to the extent that the prospects are not recognized within the NI 51-101 compliant reserve assessment, except as they are valued through the estimate of the fair market value of undeveloped land.

Pre-tax NAV at December 31, 2022[(1)(5)]

(*$ millions, except as noted*)	**Undiscounted**	**5%**	**10%**	**15%**
Total Proved plus Probable Reserves[(2)]	543.4	392.2	302.0	244.6
Fair market value of undeveloped lands[(3)]	4.4	4.4	4.4	4.4
Net debt[(5)]	(56.3)	(56.3)	(56.3)	(56.3)
NAV	**491.5**	**340.3**	**250.1**	**192.7**
Common shares outstanding (*million*)[(4)]	65.9	65.9	65.9	65.9
NAV per share (*$/share*)[(5)]	**7.46**	**5.16**	**3.80**	**2.92**

(1) Financial information is per Perpetual's 2022 audited consolidated financial statements.
(2) Reserve values per McDaniel Report as at December 31, 2022, including adjustments for natural gas market diversification contracts and carbon tax. All abandonment and reclamation obligations, including future abandonment and reclamation costs for pipelines and facilities and non-reserve wells, are included in the McDaniel Report.
(3) Independent third-party estimate; excludes undeveloped land in West Central Alberta with reserves assigned.
(4) Shares outstanding are net of shares held in trust.
(5) Non-GAAP measure, ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within these annual results.

The above evaluation includes FDC expectations required to bring undeveloped reserves on production, as recognized by McDaniel, that meet the criteria for booking under NI 51-101. The fair market value of undeveloped land does not reflect the value of the Company's extensive prospect inventory which is anticipated to be converted into reserves and production over time through future capital investment.

2023 OUTLOOK

Perpetual's Board of Directors has approved exploration and development capital spending[(1)] of $25 - $32 million for full year 2023, including $8 to $10 million to be spent in the first quarter to drill two (1.0 net) wells at East Edson and related pipeline infrastructure. The remainder of the 2023 capital program is expected to be concentrated in the third quarter of 2023 and focused primarily at East Edson. The 2023 capital program is forecast to be fully funded from the Company's credit facility and adjusted funds flow[(1)]\.

Drilling commenced on a two well pad (1.0 net) at East Edson in late February, targeting development of the Wilrich formation. During the second half of 2023, Perpetual is planning to participate at its 50% working interest in an East Edson drilling program to drill, complete, equip and tie-in an additional four to six (2.0 to 3.0 net) horizontal wells in the Wilrich formation to fill the West Wolf gas plant in order to maximize natural gas and NGL sales through next winter.

At Mannville in Eastern Alberta, Perpetual continues to monitor performance of the horizontal, multi-lateral wells drilled in 2022 targeting heavy oil in the Sparky formation. Planning activities are underway to drill one follow-up multi-lateral well in the second half of 2023. Perpetual will also continue to focus on waterflood optimization and battery consolidation projects as well as shallow gas recompletions and abandonment and reclamation activities at the Mannville property.

Exploration and development capital spending for Perpetual for full year 2023 is expected to be $25 to $32 million, with $8 to $10 million to be spent in the first quarter. The table below summarizes anticipated capital spending and drilling activities for Perpetual for the first quarter and full year of 2023.

	Q1 2023 (*$ millions*)	**# of wells (*gross/net*)**	**2023 (*$ millions*)**	**# of wells (*gross/net*)**
West Central[(1)]	$8 - $10	2 / 1.0	$22 - $28	6 - 8 / 3.0 - 4.0
Eastern Alberta	$—	—	$3 - 4	1 / 1.0
Total[(2)]	**$8 - $10**	**2 / 1.0**	**$25 - $32**	**7 - 9 / 4.0 - 5.0**

(1) Oil-based mud load fluid is recycled for future drilling operations to the extent possible, or sold and credited back to drilling capital.
(2) Excludes abandonment and reclamation spending and acquisitions or land expenditures, if any.

Total Company average production is expected to be stable year over year at 6,400 to 6,600 boe/d (22% oil and NGL) in 2023. Cash costs[(1)] are expected to be similar to 2022 levels to average between $16 and $18 per boe for the calendar year.

2023 Guidance assumptions are as follows:

	2023 Guidance
Exploration and development capital expenditures[(1)] (*$ millions*)	$25 - $32
Cash costs[(1)] (*$/boe*)	$16 - $18
Royalties (*% of revenue*)[(1)]	16 - 18%
Average daily production (*boe/d*)	6,400 - 6,600
Production mix (*%*)	22% oil and NGL

(1) Non-GAAP measure, capital management measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within these annual results.

Perpetual will continue addressing asset retirement obligations ("ARO"), with total abandonment and reclamation expenditures of approximately $1.5 to 2.0 million planned for 2023. This exceeds the Company's annual area-based closure Alberta Energy Regulatory ("AER") mandatory spending requirement of $1.35 million.

(1) Non-GAAP measure and ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within these annual results for an explanation of composition

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the year ended December 31, 2022, as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2022 and 2021. The Corporation'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"). The date of this MD&A is March 2, 2023.

This MD&A contains certain specified financial measures that are not recognized by GAAP and used by management to evaluate the performance of the Corporation and its business. Since certain specified financial measures may not have a standardized meaning, securities regulations require that specified financial measures are clearly defined, qualified and, where required, reconciled with their nearest GAAP measure. See "Non-GAAP and Other Financial Measures" for further information on the definition, calculation and reconciliation of these measures. This MD&A also contains forward-looking information. See "Forward-Looking Information". Readers are also referred to the other advisory sections in this MD&A for additional information.

NATURE OF BUSINESS: Perpetual is an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Additional information on Perpetual, including the most recently filed Annual Information Form, can be accessed at www.sedar.com or from the Corporation's website at www.perpetualenergyinc.com.

FOURTH QUARTER AND ANNUAL 2022 OPERATIONAL AND FINANCIAL HIGHLIGHTS

- Fourth quarter average production was 7,138 boe/d, up 12% from the comparative period of 2021 (Q4 2021 – 6,359 boe/d) and up 21% quarter over quarter (Q3 2022 – 5,882 boe/d) and within of the guidance to exceed 7,000 boe/d in the fourth quarter of 2022. Production for full year 2022 averaged 6,486 boe/d (20% heavy crude oil and NGL), an increase of 20% from 5,389 boe/d (24% heavy crude oil and NGL) in 2021. Production growth was driven by successful core area drilling programs. At East Edson, four (2.0 net) wells were drilled and placed on production in the fourth quarter of 2021 and six (3.0 net) Wilrich wells were drilled and placed on production during the second half of 2022. Due to high gathering line pressures, one (0.5 net) Notikewin well drilled, completed, and tied-in in 2022 was placed on production in the first quarter of 2023. At Mannville, two (2.0 net) horizontal multi-lateral heavy oil wells were drilled and placed on production late in the first quarter of 2022 and three (3.0 net) new horizontal, multi-lateral heavy oil wells were on production in the third quarter of 2022.

- Perpetual's exploration and development spending[(2)] in the fourth quarter of 2022 was minimal as both core areas completed a majority of the capital programs in the third quarter of 2022. Spending at East Edson in the fourth quarter was $1.3 million and included the remaining costs to test and place on production the seven (3.5 net) horizontal wells that were drilled during the third quarter of 2022. At Mannville in Eastern Alberta, the $1.3 million of capital recovered during the fourth quarter was related to the recovery of oil based mud ("OBM") load fluid from the three (3.0 net) wells drilled during the third quarter of 2022. Full year 2022 exploration and development capital spending totaled $31.9 million, up from $19.1 million in 2021. In 2022, the Company spent $1.6 million on Crown land purchases at East Edson with its 50% joint interest partner. In addition, close to $1.5 million was spent on asset retirement obligations ("ARO") during the year to abandon wells that had reached their end of life and execute surface lease reclamation activities, including $1.2 million of ARO spending in the fourth quarter. Four reclamation certificates were received in 2022.

- Oil and natural gas revenue for the fourth quarter of 2022 was $28.6 million, 33% higher than revenue in the comparative period of 2021 due to significantly higher reference prices for all products and the 12% increase in production. Fourth quarter revenue increased 25% from the third quarter of 2022 as production increased 21% and realized prices increased 3% on higher gas prices. Realized prices after gains on risk management contracts[(2)] decreased 5% relative to the third quarter. During the period there were $0.1 million of realized gains on risk management contracts, as compared to a realized gain of $2.1 million in third quarter. Revenue net of $4.6 million in realized losses on risk management contracts for full year 2022 was $105.1 million, close to double the $56.0 million of revenue in 2021 (net of $4.8 million of realized losses on risk management contracts) due to the combined effect of higher production and stronger realized commodity prices.

- Adjusted funds flow[(2)] in the fourth quarter of 2022 was $14.2 million ($0.22/share), up $5.6 million (65%) from the prior year period of $8.6 million ($0.13/share). Adjusted funds flow on a unit-of-production basis was $21.63/boe in the fourth quarter of 2022, a 47% increase from the prior year period of $14.67/boe, driven by the increase in commodity prices and higher production volumes. Adjusted funds flow recorded for 2022 was $48.5 million ($0.75 per share), up $31.7 million (189%) from $16.7 million ($0.27/share) in 2021.

- Net cash flows from operating activities in the fourth quarter of 2022 were $11.2 million, up $9.6 million (592%) from the comparative period of 2021 (Q4 2021 – $1.6 million). The increase was due to higher realized prices for all products and the 12% increase in production, partially offset by higher cash costs in all categories except general and administrative ("G&A") costs which were lower on higher recoveries related to overheads and costs recovered under the Management and Operating Services Agreement (the "MSA") with Rubellite. Net cash flows from operating activities for 2022 were $37.8 million (2021 - $12.8 million).

- Net income for the fourth quarter of 2022 was $9.3 million (Q4 2021 – $5.7 million). Net income in the fourth quarter of 2022 increased due to the same reasons that impacted adjusted fund flows and the $2.0 million unrealized gain on risk management contracts. Net income in 2022 was $44.4 million ($0.69/share) as compared to $81.1 million ($1.29/share) in 2021.

- Cash costs[(2)] were $9.1 million or $13.86/boe in the fourth quarter of 2022, up 8% (down 4% on a unit-of-production basis) from the comparative period (Q4 2021 – $8.4 million or $14.41/boe). The increase was due to the impact of higher production, partially offset by lower G&A costs due to higher recoveries. Cash costs were $34.4 million ($14.55/boe) in 2022, up 23% from 2021 ($2021 - $27.9 million; $14.19/boe) as inflationary pressures were somewhat offset by efficiency gains related to higher production levels across a largely fixed operating cost base.

- As at December 31, 2022, net debt[(2)] was $56.3 million, a decrease of 4% from December 31, 2021, as adjusted funds flow exceeded capital expenditures and payments related to the retained East Edson royalty obligations during 2022. As compared to the third quarter of 2022, net debt decreased $9.8 million (15%) as adjusted funds flow exceeded capital expenditures during the fourth quarter. The majority of Perpetual's 2022 capital spending at East Edson and Mannville was executed during the third quarter, with production additions gradually contributing to sales volumes by late September. By December 31, 2022, higher sales volumes combined with limited additional capital spending during the fourth quarter generated free funds flows[(2)] which was applied to reduce bank debt.

- Perpetual had available liquidity (see "Capital Management") at December 31, 2022 of $13.9 million, comprised of the $30.0 million borrowing limit of Perpetual's first lien credit facility ("Credit Facility Borrowing Limit") Credit Facility Borrowing Limit, less current borrowings and letters of credit of $14.9 million and $1.2 million, respectively.

(1) See "Fourth Quarter Financial and Operating - Production" section of this MD&A for details of product components that comprise Perpetual's boe production.
(2) Non-GAAP measure and ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

2023 OUTLOOK

Perpetual's Board of Directors has approved exploration and development capital spending[1] of $25 - $32 million for full year 2023, including $8 to $10 million to be spent in the first quarter to drill two (1.0 net) wells at East Edson and related pipeline infrastructure. The remainder of the 2023 capital program is expected to be concentrated in the third quarter of 2023 and focused primarily at East Edson. The 2023 capital program is forecast to be fully funded from the Company's credit facility and adjusted funds flow[1].

Drilling commenced on a two well pad (1.0 net) at East Edson in late February, targeting development of the Wilrich formation. During the second half of 2023, Perpetual is planning to participate at its 50% working interest in an East Edson drilling program to drill, complete, equip and tie-in an additional four to six (2.0 to 3.0 net) horizontal wells in the Wilrich formation to fill the West Wolf gas plant in order to maximize natural gas and NGL sales through next winter.

At Mannville in Eastern Alberta, Perpetual continues to monitor performance of the horizontal, multi-lateral wells drilled in 2022 targeting heavy oil in the Sparky formation. Planning activities are underway to drill one follow-up multi-lateral well in the second half of 2023. Perpetual will also continue to focus on waterflood optimization and battery consolidation projects as well as shallow gas recompletions and abandonment and reclamation activities at the Mannville property.

Exploration and development capital spending for Perpetual for full year 2023 is expected to be $25 to $32 million, with $8 to $10 million to be spent in the first quarter. The table below summarizes anticipated capital spending and drilling activities for Perpetual for the first quarter and full year of 2023.

	Q1 2023 (*$ millions*)	**# of wells (*gross/net*)**	**2023 (*$ millions*)**	**# of wells (*gross/net*)**
West Central	$8 - $10	2 / 1.0	$22 - $28	6 - 8 / 3.0 - 4.0
Eastern Alberta[1]	$—	—	$3 - 4	1 / 1.0
Total[2]	**$8 - $10**	**2 / 1.0**	**$25 - $32**	**7 - 9 / 4.0 - 5.0**

(1) Oil-based mud load fluid is recycled for future drilling operations to the extent possible, or sold and credited back to drilling capital.
(2) Excludes abandonment and reclamation spending and acquisitions or land expenditures, if any.

Total Company average production is expected to be stable year over year at 6,400 to 6,600 boe/d (22% oil and NGL) in 2023. Cash costs (see "Non-GAAP and Other Financial Measures") are expected to be similar to 2022 levels to average between $16 and $18 per boe for the calendar year.

2023 Guidance assumptions are as follows:

	2023 Guidance
Exploration and development expenditures[1][2] (*$ millions*)	$25 - $32
Cash costs[1] (*$/boe*)	$16 - $18
Royalties (% of revenue)[1]	16 - 18%
Average daily production (*boe/d*)	6,400 - 6,600
Production mix (%)	22% oil and NGL

(1) Non-GAAP measure and ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.
(2) Excludes abandonment and reclamation spending and acquisitions or land expenditures, if any.

Perpetual will continue addressing asset retirement obligations ("ARO"), with total abandonment and reclamation expenditures of approximately $1.5 to 2.0 million planned for 2023. This exceeds the Company's annual area-based closure Alberta Energy Regulatory ("AER") mandatory spending requirement of $1.4 million.

(1) Non-GAAP measure and ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

FOURTH QUARTER FINANCIAL AND OPERATING RESULTS

Cash Flow used in Investing Activities, Capital Expenditures, Acquisitions and Dispositions

Cash flow used in investing activities for the three and twelve months ended December 31, 2022 was $6.8 million (Q4 2021 - $49.2 million) and $40.9 million (2021 - $43.7 million). In addition to cash flow used in investing activities, Perpetual uses capital expenditures to measure its capital investments compared to the Company's annual budgeted expenditures, which excludes acquisition and disposition activities. "Capital expenditures" is not a standardized measure and, therefore, may not be comparable with the calculation of similar measures by other entities.

For reconciliation of cash flow used in investing activities to capital expenditures, refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A.

The following table summarizes capital spending for both property, plant and equipment assets and exploration and evaluation assets, excluding non-cash items:

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands)	**2022**	2021	**2022**	2021
Exploration and development	**8**	7,558	**31,772**	19,060
Corporate assets	**107**	—	**137**	2
Capital expenditures	**115**	7,558	**31,909**	19,062

Exploration and development spending by area

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands)	**2022**	2021	**2022**	2021
West Central	**1,283**	7,382	**18,977**	15,522
Eastern Alberta	**(1,275)**	176	**12,795**	3,538
Total	**8**	7,558	**31,772**	19,060

Wells drilled by area

	Three months ended December 31,		Twelve months ended December 31,	
(gross/net)	**2022**	2021	**2022**	2021
West Central	**-/-**	4.0/2.0	**7/3.5**	9/4.5
Eastern Alberta	**-/-**	-/-	**5/5.0**	5/4.0
Total	**-/-**	4.0/2.0	**12/8.5**	14/8.5

Perpetual's exploration and development capital spending in 2022 was $31.8 million, of which $19.0 million was attributable to the East Edson drilling program, which restarted at the end of the second quarter and resulted in seven (3.5 net) wells drilled, completed, equipped, tied-in and six (3.0 net) placed on production. Due to high line pressures, the remaining one (0.5 net) well was placed on production in the first quarter of 2023. At Mannville in Eastern Alberta, the Company spent $12.8 million to drill, complete and place on production five (5.0 net) horizontal, multi-lateral wells, targeting heavy oil in the Sparky formation during 2022. The Company also spent $1.6 million on Crown land purchases at East Edson with its 50% joint interest partner during 2022.

Perpetual's exploration and development spending in the fourth quarter of 2022 was minimal, of which $1.3 million was attributable to the East Edson drilling program. Costs in the fourth quarter were remaining costs to complete, test and place on production the three (1.5 net) horizontal wells that were drilled during the third quarter of 2022. At Mannville in Eastern Alberta, the $1.3 million of capital recovered during the fourth quarter was related to the recovery of OBM load fluid from the three (3.0 net) wells drilled during the third quarter of 2022. Recoveries of OBM are not recorded as sales production as the OBM is recycled for future drilling operations to the extent possible, or sold and credited back to drilling capital. The Company also spent $0.3 million on Crown land purchases at East Edson with its 50% joint interest partner in the fourth quarter of 2022.

Acquisitions and Dispositions

There were no acquisitions or dispositions during 2022.

During the first quarter of 2021, Perpetual participated for its 50% working interest in the acquisition of certain undeveloped lands, wells, pipelines and gross overriding royalties from a third party in the East Edson core area, for net consideration of $0.6 million. Dispositions during the first quarter of 2021 also included the sale of non-operated equipment for net proceeds to Perpetual of $0.2 million.

On September 3, 2021, the Company closed the sale of the Clearwater assets in Eastern Alberta (the "Clearwater Assets") to Rubellite for total consideration of $65.5 million, including $53.6 million in promissory notes, the assumption by Rubellite of $5.8 million in promissory notes due to 197Co, the return to Perpetual of 8.2 million Perpetual common shares valued at $2.8 million, 0.7 million Rubellite common shares ("AIMCo Bonus Shares") valued at $1.4 million, and the issuance of Rubellite Share Purchase Warrants to purchase 4.0 million Rubellite common shares valued at $2.0 million (the "Rubellite Transaction"). The promissory notes related to the Rubellite Transaction were repaid on October 5, 2021.

Expenditures on decommissioning obligations

During the fourth quarter of 2022, Perpetual executed $1.2 million (Q4 2021 – $0.6 million) of abandonment and reclamation projects, of which $0.1 million (Q4 2021 - $0.2 million) was funded by SRP. SRP funding is presented on the consolidated statements of income and comprehensive income as other income. There were 3 reclamation certificates received from the Alberta Energy Regulator ("AER") during the fourth quarter of 2022 and a total of 4 for the year (2021 – 15 reclamation certificates). Total abandonment and reclamation expenditures of $1.5 million were completed in 2022, with $0.3 million funded through the SRP. Abandonment and reclamation spending eventually leads to the cessation of associated property tax and surface lease expenses, reducing future operating costs. Subsequent to year-end, one additional reclamation certificate was received from the AER.

Production

	Three months ended December 31,		Twelve months ended December 31,	
	2022	2021	**2022**	2021
Production				
Conventional natural gas *(Mcf/d)*[1]	**33,024**	31,500	**31,033**	24,568
Conventional heavy crude oil *(bbl/d)*[2]	**1,126**	714	**898**	963
NGL *(bbl/d)*[3]	**508**	395	**416**	331
Total production (*boe/d*)	**7,138**	6,359	**6,486**	5,389

(1) Conventional natural gas production yielded a heat content of 1.17 GJ/Mcf for the three months ended December 31, 2022 (Q4 2021 – 1.17), resulting in higher realized natural gas prices on a $/Mcf basis.
(2) Primarily from Eastern Alberta.
(3) Primarily from West Central which produces liquids-rich conventional natural gas.

	Three months ended December 31,		Twelve months ended December 31,	
	2022	2021	**2022**	2021
Production by core area				
West Central	**5,493**	5,178	**5,149**	4,008
Eastern Alberta	**1,645**	1,181	**1,337**	1,381
Total production *(boe/d)*	**7,138**	6,359	**6,486**	5,389

Fourth quarter production averaged 7,138 boe/d, up 12% from 6,359 boe/d in the comparative period of 2021. In the fourth quarter of 2022, the production mix was comprised of 77% conventional natural gas and 23% conventional heavy crude oil and NGL, as compared to 83% of conventional natural gas and 17% conventional heavy crude oil and NGL in the fourth quarter of 2021. Production levels steadily increased during the fourth quarter of 2022 as six (3.0 net) Edson wells were added late in the third quarter of 2022 and five (5.0 net) Mannville wells were brought on production during the second and third quarters of 2022.

Fourth quarter conventional natural gas production averaged 33.0 MMcf/d, an increase of 5% from 31.5 MMcf/d in the comparative period of 2021 with production additions from six (3.0 net) of the new East Edson liquids-rich gas wells beginning to contribute to production midway through the second half of 2022, partially offset by natural declines.

Conventional heavy crude oil production averaged 1,126 bbl/d which was 58% higher than the fourth quarter of 2021. The increase year-over-year was primarily due to the five (5.0 net) new multi-lateral heavy oil wells drilled at Mannville and brought on production through the second and third quarters of 2022.

Fourth quarter NGL production was 508 bbl/d, 29% higher than the comparative period of 2021. The increase in NGL production is closely tied to higher conventional natural gas production at East Edson, where NGL yields were 17.0 bbl per MMcf in the fourth quarter of 2022 (Q4 2021 – 12.5 bbl per MMcf). Perpetual's average NGL sales composition for the fourth quarter of 2022 consisted of 55% condensate, slightly higher than the prior year period when condensate represented 53% of total NGL production as additional capital was spent during the second half of 2022 on facility optimization to reduce emissions and increase NGL recoveries.

For the twelve months ended December 31, 2022, production increased 20% to 6,486 boe/d compared to 5,389 boe/d in the comparative 2021 period. Production levels steadily increased as new wells were brought on production in both core areas, partially offset by the disposition of the Clearwater Assets in the third quarter of 2021 and natural declines.

Oil and Natural Gas Revenue

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands, except as noted*)	**2022**	2021	**2022**	2021
Oil and natural gas revenue				
Natural gas	**17,546**	13,914	**66,781**	33,012
Oil	**7,368**	4,863	**29,538**	20,172
NGL	**3,665**	2,672	**13,368**	7,630
Oil and natural gas revenue	**28,579**	21,449	**109,687**	60,814

	Three months ended December 31,		Twelve months ended December 31,	
	2022	2021	**2022**	2021
Average Benchmark Prices				
NYMEX Daily Index *(US$/MMBtu)*	**5.59**	5.83	**6.47**	3.84
AECO 5A Daily Index *($/GJ)*	**4.94**	4.18	**5.06**	3.26
AECO 5A Daily Index *($/Mcf)*(1)	**5.21**	4.41	**5.34**	3.44
West Texas Intermediate ("WTI") *(US$/bbl)*	**82.64**	77.13	**94.22**	67.90
Exchange rate *(US$/CAD$)*	**1.36**	1.26	**1.30**	1.25
West Texas Intermediate ("WTI") *(CAD$/bbl)*	**112.39**	97.18	**122.49**	84.88
Western Canadian Select ("WCS") *(CAD$/bbl)*	**77.33**	78.65	**98.49**	68.76
WCS differential to WTI *(US$/bbl)*	**(25.70)**	(14.63)	**(18.23)**	(13.04)
Perpetual Average Realized Prices(2)				
Natural gas *($/Mcf)*	**5.78**	4.80	**5.90**	3.15
Oil *($/bbl)*	**71.14**	73.96	**90.15**	57.36
NGL *($/bbl)*	**78.36**	73.44	**88.05**	63.24
Average realized price *($/boe)*	**43.52**	36.66	**46.33**	30.92

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Non-GAAP ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

Perpetual's oil and natural gas revenue for the three months ended December 31, 2022 of $28.6 million was a 33% increase from $21.4 million in the comparative period due to the 12% increase in average production combined with the impact of higher reference prices for all products. Oil and natural gas revenue for the twelve months ended December 31, 2022 of $109.7 million was 80% higher than 2021, due to higher reference prices and the 20% increase in average production.

Natural gas revenue of $17.5 million in the fourth quarter of 2022 comprised 61% (Q4 2021 – 65%) of total revenue while natural gas production was 77% (Q4 2021 – 83%) of total production. Natural gas revenue was 26% higher than the comparative period (Q4 2021 – $13.9 million), reflecting the combined impact of higher AECO Daily Index prices and the 5% increase in conventional natural gas production volumes driven by drilling activity at East Edson. For the twelve months ended December 31, 2022, natural gas revenue was 102% higher than the prior year, as a result of the 26% increase in average production and higher AECO gas prices.

Oil revenue of $7.4 million represented 26% (Q4 2021 –23%) of total revenue while conventional heavy crude oil production was 16% (Q4 2021 – 11%) of total production. Oil revenue was 52% higher than the fourth quarter of 2021, as a result of the 58% increase in heavy crude oil production. Compared to the fourth quarter of 2021, the WCS average price of $77.33/bbl (Q4 2021 - $78.65/bbl) was down slightly as the increase in WTI coupled with the increase in the US$/CAD$ exchange rate was offset by the widening WCS differential on WTI oil prices. Perpetual's realized oil prices further reflects a price offset for quality which averaged $6.19/bbl during the quarter (Q4 2021 - $8.34/bbl). For the twelve months ended December 31, 2022, oil revenue was 46% higher compared to the prior year, as a result of higher reference prices, partially offset by the widening differential between WCS and WTI oil prices and the 7% decline in average production as result of the sale of the Clearwater Assets.

NGL revenue for the fourth quarter of 2022 of $3.7 million represented 13% (Q4 2021 – 12%) of total revenue while NGL production was 7% (Q4 2021 – 6%) of total production. NGL revenue increased 37% from the comparative period, reflecting the 29% increase in NGL production which was driven by both higher gas production and the 23% increase in NGL yield at East Edson as well as the increase in NGL component prices compared to the prior year period, in step with the rise in WTI oil prices. For the twelve months ended December 31, 2022, NGL revenue was 75% higher than the prior year, as a result of the 26% increase in average production and higher reference prices.

Risk Management Contracts

The Company uses financial derivatives, physical delivery contracts and market diversification strategies to manage commodity price risk. Derivative contracts are put in place to manage fluctuations in commodity prices, protecting Perpetual's cash flows from potential volatility. The Company's market diversification strategies balance pricing exposure over multiple markets and are put in place to mitigate market and delivery point risks and dislocations. As a result, Perpetual's realized prices deviate from the index prices. The Company uses "average realized prices after risk management contracts" which is not a standardized measure, and therefore may not be comparable with the calculation of similar measures by other entities. The measure is used by management to calculate the Company's net realized commodity prices, taking into account the monthly settlements of physical and financial crude oil and natural gas forward sales, collars, basis differentials and forward foreign exchange sales.

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2022**	2021	**2022**	2021
Unrealized gain (loss) on foreign exchange contracts	**218**	—	**30**	—
Unrealized gain (loss) on natural gas contracts	**1,412**	1,551	**2,159**	4,033
Unrealized gain (loss) on oil contracts	**337**	(249)	**1,298**	(300)
Unrealized gain (loss) on risk management contracts	**1,967**	1,302	**3,487**	3,733
Realized gain (loss) on natural gas contracts	**374**	1	**(491)**	(4,748)
Realized gain (loss) on oil contracts	**(225)**	(62)	**(4,129)**	(62)
Realized gain (loss) on risk management contracts	**149**	(61)	**(4,620)**	(4,810)
Change in fair value of risk management contracts	**2,116**	1,241	**(1,133)**	(1,077)

The following table calculates average realized prices after risk management contracts, which is not a standardized measure:

	Three months ended December 31,		Twelve months ended December 31,	
	2022	2021	**2022**	2021
Realized gain (loss) on risk management contracts [(1)]				
Realized gain (loss) on natural gas contracts *($/Mcf)*	**0.12**	(0.02)	**(0.04)**	(0.54)
Realized loss on oil contracts *($/bbl)*	**(2.17)**	—	**(12.60)**	—
Realized gain (loss) on risk management contracts (*$/boe*)	**0.21**	(0.10)	**(1.96)**	(2.45)
Average realized prices after risk management contracts[(1)]				
Natural gas *($/Mcf)*	**5.90**	4.80	**5.86**	3.15
Oil *($/bbl)*	**68.97**	73.96	**77.55**	57.36
NGL (*$/bbl*)	**78.36**	73.44	**88.05**	63.24
Average realized price (*$/boe)*	**43.73**	36.56	**44.37**	28.47

(1) Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

Realized gains on risk management contracts totaled $0.1 million for the fourth quarter of 2022, compared to losses of $0.1 million for the comparative period of 2021. Realized losses on risk management contracts totaled $4.6 million for the twelve months of 2022 (2021 - $4.8 million realized loss).

Unrealized gains on risk management contracts were $2.0 million in the fourth quarter of 2022 (Q4 2021 – unrealized gains of $1.3 million) and unrealized gains were $3.5 million for the year ended December 31, 2022 (2021 – unrealized gains of $3.7 million). Unrealized gains and losses represent the change in mark-to-market value of derivative contracts as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on derivatives are excluded from the Company's calculation of cash flow from operating activities as non-cash items. Derivative gains and losses vary depending on the nature and extent of derivative contracts in place, which in turn, vary with the Company's assessment of commodity price risk, committed capital spending and other factors.

Royalties

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands, except as noted*)	**2022**	2021	**2022**	2021
Crown royalties				
Natural gas	**1,533**	460	**5,411**	126
Oil	**91**	595	**1,999**	1,116
NGL	**856**	203	**2,104**	860
Total Crown royalties	**2,480**	1,257	**9,514**	2,102
Freehold and overriding royalties				
Natural gas	**1,643**	1,753	**6,888**	4,849
Oil	**1,000**	378	**3,388**	1,607
NGL	**154**	397	**1,000**	1,364
Total freehold and overriding royalties	**2,797**	2,528	**11,276**	7,820
Total royalties	**5,277**	3,786	**20,790**	9,920
$/boe	**8.04**	6.47	**8.78**	5.04
Royalties as a percentage of revenue[(1)]				
Crown	**8.7**	5.9	**8.7**	3.5
Freehold and overriding	**9.8**	11.8	**10.3**	12.9
Total *(% of oil and natural gas revenue)*	**18.5**	17.7	**19.0**	16.4
Natural gas royalties *(% of natural gas revenue)*	**18.1**	15.9	**18.4**	15.1
Oil royalties *(% of oil revenue)*	**14.8**	20.0	**18.2**	13.5
NGL royalties *(% of NGL revenue)*	**27.6**	22.5	**23.2**	29.1

(1) Non-GAAP ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

Total royalties for the fourth quarter of 2022 were $5.3 million, 39% higher than the fourth quarter of 2021. On a unit-of-production basis, royalties were up 24% to $8.04/boe (Q4 2021 – $6.47/boe). During the fourth quarter of 2022, royalties were significantly higher as a result of increased production and higher reference prices. The combined average royalty rate increased from 2021 as royalty rates escalate with price under the Crown royalty regime in Alberta. Freehold and overriding royalties increased to $2.8 million from $2.5 million in the fourth quarter of 2021, due to the impact of higher AECO Daily Index and NGL prices.

For the twelve months ended December 31, 2022, royalties were $20.8 million (2021 – $9.9 million), 110% higher than 2021. On a unit-of-production basis, royalties were up 74% to $8.78/boe (2021 – $5.04/boe). Royalties increased relative to 2021, as the Alberta Gas Reference price and AECO Daily index prices, which are used to calculate Crown royalties and certain overriding royalties respectively, increased significantly during 2022 along with oil and NGL prices. In addition, there was a $1.2 million one-time Gas Cost Allowance ("GCA") adjustment on royalties in 2022 which increased royalties for the year ended December 31, 2022 by $0.51/boe.

As part of the sale of 50% of the East Edson property on April 1, 2020, Perpetual had agreed to retain its joint venture partner's 50% working interest in the existing gross overriding royalty obligation on the property, equivalent to 2.8 MMcf/d of natural gas and associated NGL production, for the period April 1, 2020 to December 31, 2022. This obligation has been recorded in the consolidated statement of financial position under the heading "Royalty obligations". Prior to November 1, 2021, the retained East Edson royalty obligation was paid in-kind, and settled through non-cash delivery of contractual natural gas and NGL volumes to the royalty holder. As of November 1, 2021, the royalty obligation is settled through payment in cash. This obligation as of December 31, 2022 has been fully paid.

Production and operating expenses

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2022**	2021	**2022**	2021
Production and operating expenses	**3,828**	2,862	**16,107**	12,859
$/boe	**5.83**	4.89	**6.80**	6.54

Total production and operating expenses increased 19% on a unit-of-production basis to $5.83/boe for the fourth quarter of 2022, compared to $4.89/boe for the fourth quarter of 2021. The increase was related to higher heavy crude oil production as a percentage of total volumes as it has higher operating costs than the Company's conventional natural gas and NGL production at East Edson. Also contributing to higher costs in the fourth quarter of 2022 was higher purchased energy costs at the non-operated East Edson gas processing facility.

For the twelve months ended December 31, 2022, production and operating expenses increased 4% on a unit-of-production basis to $6.80/boe, compared to $6.54/boe for 2021. The increase was due to increased heavy crude oil production in the second half of 2022, along with higher costs in all areas such as chemicals, taxes, purchased energy and well servicing costs. This increase was partially offset by increased conventional natural gas and NGL production at East Edson which has a higher percentage of fixed operating costs and lower overall operating costs than the Company's conventional heavy crude oil production.

On an absolute dollar basis, production and operating costs increased on higher production volumes.

Transportation costs

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2022**	2021	**2022**	2021
Transportation costs	**1,223**	871	**3,872**	2,993
$/boe	**1.86**	1.49	**1.64**	1.52

Transportation costs include clean oil trucking and NGL transportation, as well as costs to transport natural gas from the plant gate to commercial sales points. Transportation costs in the fourth quarter of 2022 were $1.2 million, a 40% increase from the comparative period of 2021, as a result of higher average production volumes. On a unit-of-production basis, transportation costs increased by 25% to $1.86/boe in the fourth quarter of 2022 (Q4 2021 – $1.49/boe) due to increases in oil trucking costs primarily as a result of higher fuel costs and surcharges and the increase in heavy crude oil production as a percentage of total volumes.

For the twelve months ended December 31, 2022, transportation costs were $3.9 million, an increase of 29% over 2021 on higher average production volumes. On a unit-of-production basis, transportation costs increased by 8% to $1.64/boe (2021 – $1.52/boe) due to higher oil trucking costs in the second half of 2022 and increased transportation rates on the Nova Gas Transportation Line ("NGTL') system.

Operating netbacks

"Operating netback" is a non-GAAP measure determined by deducting royalties, production and operating expenses, and transportation costs from oil and natural gas revenue. Operating netback is also calculated on a per boe basis using total production sold in the period. Perpetual considers operating netback to be an important performance measure to evaluate its operational performance as it demonstrates its profitability relative to commodity prices. Operating netback is not a standardized measure and, therefore, may not be comparable with the calculation of similar measures by other entities.

The following table highlights Perpetual's operating netbacks for the three and twelve months ended December 31, 2022 and 2021:

	Three months ended December 31,				Twelve months ended December 31,			
($/boe) ($ thousands)		**2022**		2021		**2022**		2021
Production (*boe/d*)		**7,138**		6,359		**6,486**		5,389
Oil and natural gas revenue	**43.52**	**28,579**	36.66	21,449	**46.33**	**109,687**	30.92	60,814
Royalties	**(8.04)**	**(5,277)**	(6.47)	(3,786)	**(8.78)**	**(20,790)**	(5.04)	(9,920)
Production and operating expenses	**(5.83)**	**(3,828)**	(4.89)	(2,862)	**(6.80)**	**(16,107)**	(6.54)	(12,859)
Transportation costs	**(1.86)**	**(1,223)**	(1.49)	(871)	**(1.64)**	**(3,872)**	(1.52)	(2,993)
Operating netback[(1)]	**27.79**	**18,251**	23.81	13,930	**29.11**	**68,918**	17.82	35,042
Realized gain (loss) on risk management contracts	**0.21**	**149**	(0.10)	(61)	**(1.96)**	**(4,620)**	(2.45)	(4,810)
Total operating netback, including risk management contracts	**28.00**	**18,400**	23.71	13,869	**27.15**	**64,298**	15.37	30,232

(1) Non-GAAP measure. Refer to the section entitled "Non-GAAP and Other Financial Measures" for an explanation of composition.

For the fourth quarter of 2022, Perpetual's operating netback, including risk management contracts, was $18.4 million ($28.00/boe), up 33% from $13.9 million ($23.71/boe) in the comparative period of 2021. The increase was due to higher oil and natural gas revenue driven by increased pricing for all commodities being applied to higher average production volumes and a realized hedging gain. The increase in the fourth quarter of 2022 was partially offset by higher royalties and higher costs in all areas.

For the twelve months ended December 31, 2022 the operating netback, including risk management contracts, was $64.3 million ($27.15/boe) a 113% increase from $30.2 million ($15.37/boe) in 2021. On a unit-of-production basis, the operating netback increased 77% year-over-year. The increase was due to higher oil and natural gas revenue, partially offset by increased costs in all areas and higher royalties driven by higher pricing and the one-time GCA adjustment.

General and administrative ("G&A") expenses

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2022**	2021	**2022**	2021
G&A expense before overhead recoveries	**4,542**	3,847	**14,688**	11,451
MSA recoveries[1]	**(561)**	(303)	**(1,859)**	(438)
Overhead recoveries	**(1,126)**	113	**(2,918)**	(256)
Total G&A expense	**2,855**	3,657	**9,911**	10,757
$/boe	**4.35**	6.25	**4.19**	5.47

(1) Concurrent with the sale of the Clearwater Assets to Rubellite on September 3, 2021, Perpetual entered into a Management and Operating Services Agreement (the "MSA") with Rubellite whereby Perpetual receives payment for certain technical and administrative services provided to Rubellite.

For the three and twelve months ended December 31, 2022, G&A expenses of $2.9 million and $9.9 million decreased 22% and 8%, respectively over the comparative periods. Prior to overhead recoveries, G&A increased over the prior year due to higher employee salaries and benefits, which had been reduced in the prior year in response to the collapse in commodity prices and were gradually re-instated over the second half of 2021. Other increases were related to higher office and administrative costs, partially offset by lower professional fees. Overhead recoveries were higher due to increased capital spending and higher absolute production and operating costs.

For the three and twelve months ended December 31, 2022, the costs billed under the MSA to Rubellite were $0.6 million and $1.9 million, respectively. MSA recoveries in 2022 increased over the comparative period as a result of Rubellite's higher capital activity and increased production. The MSA began in 2021 concurrent with the sale of the Clearwater Assets to Rubellite on September 3, 2021.

During 2021 Perpetual received payments from the Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") programs which reduced general and administrative expenses by $0.1 million during the fourth quarter of 2021 and $0.8 million during 2021. There were no payments received in 2022.

Share-based payments

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2022**	2021	**2022**	2021
Share-based payments (non-cash)	**740**	149	**6,184**	360
Share-based payments (cash)	**124**	319	**1,250**	1,684
Total share-based payments	**864**	468	**7,434**	2,044

Share-based payments expense for the three and twelve months ended December 31, 2022 increased to $0.9 million and $7.4 million, respectively, from $0.5 million and $2.0 million in the comparative periods of 2021. The increase in non-cash share-based payments expense is due to an increase in the fair value of grants issued in 2022, which is attributed to the increase in the Company's share price. This was partially offset by a reduction in the cash share-based payments as this plan ended during the fourth quarter of 2022.

During the fourth quarter of 2022, 0.1 million deferred options, 0.1 million deferred shares and 0.1 million restricted rights were granted to Officers, Directors, and employees of the Company. For the twelve months ended December 31, 2022, 1.5 million deferred options, 0.8 million deferred shares, 1.3 million share options, 0.8 million performance share rights, and 3.1 million restricted rights were granted to Officers, Directors and employees of the Company.

Depletion and depreciation

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2022**	2021	**2022**	2021
Depletion and depreciation	**5,633**	4,182	**17,962**	14,020
$/boe	**8.58**	7.15	**7.59**	7.13

The Company calculates depletion using the net book value of the asset, future development costs associated with proved and probable reserves, salvage values on associated production equipment, as well as proved and probable reserves. As at December 31, 2022, depletion was calculated on a $176.1 million depletable balance and $104.6 million in future development costs (2021 – $141.5 million depletable balance and $75.3 million in future development costs). The depletable base excluded an estimated $3.8 million (2021 – $3.4 million) of salvage value.

Depletion and depreciation expense for the fourth quarter of 2022 was $5.6 million or $8.58/boe (Q4 2021 – $4.2 million or $7.15/boe). Depletion and depreciation expense for the twelve months ended December 31, 2022 was $18.0 million or $7.59/boe (2021 – $14.0 million or $7.13/boe). The increases reflect higher average production volumes compared to the comparative periods. On a unit-of-production basis, depletion and depreciation expense increased by 20% compared to the fourth quarter of 2021 and increased by 6% compared to 2021 due to an increase in the depletion rate driven by higher production relative to reserve additions and reversals of impairment booked in 2021 and 2022. Depletion and depreciation expense will fluctuate from one period to the next depending on the amount of capital spent, the amount of reserves added and volumes produced.

Impairment

There were no indicators of impairment for the Company's cash generating units "CGU"s as of December 31, 2022 and therefore an impairment test was not performed.

During the first quarter of 2022, the Company determined that indicators of impairment reversal existed and that the estimated recoverable amounts of the Eastern Alberta CGU exceeded the carrying amounts of $44.8 million. Accordingly, a non-cash impairment reversal of $7.4 million was included in net income. All previous impairment charges that were eligible for reversal had all been reversed as at March 31, 2022 for property, plant and equipment.

During the fourth quarter of 2021, the Company determined that indicators of impairment reversal existed and that the estimated recoverable amounts of the Eastern Alberta CGU exceeded the carrying amounts of $42.2 million. Accordingly, a non-cash impairment reversal of $0.5 million was included in net income.

E&E assets are tested for impairment both at the time of any triggering facts and circumstances as well as upon their reclassification to oil and gas properties in PP&E.

At December 31, 2022, the Company conducted an assessment of indicators of impairment and impairment reversal for the Company's E&E assets and no indicators were identified. The Company transferred undeveloped land to PP&E at a value of $0.2 million, which was equal to the book value in E&E. As a result of the transfer, an impairment test was required on transfer to PP&E and there were no impairments recorded to E&E as at December 31, 2022.

Finance expense

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands)	**2022**	2021	**2022**	2021
Cash finance expense				
Interest on revolving bank debt	**334**	150	**1,031**	953
Interest on term loan	**55**	53	**216**	53
Interest on 2025 Senior Notes(2)	**780**	1,408	**3,184**	1,408
Interest on 2022 Senior Notes(1)	**—**	(608)	**—**	(1,253)
Interest on lease liabilities	**26**	36	**116**	148
Total cash finance expense	**1,195**	1,039	**4,547**	1,309
Non-cash finance expense				
Interest paid in-kind on term loan	**—**	—	**—**	2,743
Interest on 2022 Senior Notes(1)	**—**	—	**—**	1,469
Interest paid in-kind on 2025 Senior Notes(2)	**—**	—	**—**	1,533
Gain on senior note maturity extension	**—**	—	**—**	(1,591)
Gain on senior note extinguishment(3)	**—**	—	**(101)**	(6,820)
Gain on Term Loan substantive modification	**—**	—	**—**	—
Amortization of debt issue costs	**434**	235	**1,864**	962
Accretion on decommissioning obligations	**203**	165	**727**	531
Change in fair value of other liability	**60**	131	**1,678**	1,159
Change in fair value of royalty obligations	**(363)**	(663)	**2,256**	4,101
Total non-cash finance expense	**334**	(132)	**6,424**	4,087
Finance expense recognized in net income (loss)	**1,529**	907	**10,971**	5,396

(1) During 2022, the Company settled semi-annual interest payments in cash, rather than payment-in-kind which was the method used in 2021.
(2) On January 22, 2021, Perpetual's 2022 Senior Notes were exchanged for 2025 Senior Notes, providing Perpetual the option to pay interest in-kind ("PIK"). Perpetual elected to pay the January 23, 2021 semi-annual interest of $1.5 million by a PIK Interest Payment. As a result, the previously accrued 2022 Senior Notes cash interest of $1.3 million was reversed and replaced by $1.3 million of 2025 Senior Note non-cash interest expense. The Company satisfied the semi-annual interest payment due July 23, 2021 by a PIK Interest Payment and accrued $0.8 million of non-cash interest expense for the three months ended March 31, 2021.
(3) During the twelve months ended December 31, 2022 the Company purchased and cancelled $0.9 million of Senior Notes outstanding for gross proceeds of $0.8 million, resulting in a gain on extinguishment of $0.1 million.

Total cash finance expense was $1.2 million in the fourth quarter of 2022, 15% higher than the comparative 2021 period as a result of increased interest rates and higher outstanding bank debt (Q4 2021 – $1.0 million). For the twelve months ended December 31, 2022, cash finance expense was $4.5 million (2021 – $1.3 million) which reflected the payment of interest in cash in 2022 rather than in-kind, partially offset by higher interest on revolving bank debt.

Total non-cash finance expense for the fourth quarter of 2022 was $0.3 million, higher than the comparative period (Q4 2021 – $0.1 million income). For the twelve months ended December 31, 2022, non-cash finance expense was $6.4 million (2021 – $4.1 million). During 2022, the increase was attributable to the payment of interest on the Senior Notes and Term Loan in cash rather than in-kind. Non-cash finance expense is also driven by the change in the fair value of the royalty obligations which is sensitive to changing AECO natural gas and NGL prices and the recognition of future contingent payments related to the Second Lien Loan Settlement which are recorded as other liability with the change being recognized through finance expense. The increase in the fourth quarter was driven by the change in the fair value of the royalty obligations. Perpetual's extra royalty obligation at East Edson terminated December 31, 2022.

LIQUIDITY AND CAPITAL RESOURCES

Perpetual's strategy targets the maintenance of a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions such as depressed commodity prices, available liquidity, and the risk characteristics of its underlying oil and natural gas assets. The Company considers its capital structure to include share capital, senior notes, the Term Loan, revolving bank debt, and adjusted net working capital. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell assets, and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short-term liquidity and long-term financial sustainability.

Perpetual uses net debt, adjusted working capital, enterprise value, free funds flow and trailing twelve-months adjusted funds flow as important indicators of capital resources, management and liquidity. These are not standardized measures, and therefore may not be comparable with the calculation of similar measures by other entities, refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A.

Capital management

($ thousands, except as noted)	December 31, 2022	December 31, 2021
Revolving bank debt	**14,909**	2,487
Term loan, principal amount	**2,671**	2,671
Senior notes, principal amount	**35,647**	36,852
Other liability, undiscounted amount	**3,342**	1,387
Adjusted working capital deficiency (surplus)(1)	**(220)**	16,143
Net debt(1)	**56,349**	59,270
Shares outstanding at end of period (thousands)(3)	**65,944**	63,567
Market price at end of period ($/share)	**0.71**	0.70
Market value of shares(1)	**46,820**	44,496
Enterprise value(1)	**112,764**	103,767
Net debt as a percentage of enterprise value(2)	**50%**	57%
Trailing twelve-months adjusted funds flow(1)	**48,471**	16,746
Net debt to adjusted funds flow(2)	**116%**	354%

(1) Non-GAAP measure. Refer to the section entitled "Non-GAAP and Other Financial Measures" for an explanation of composition.
(2) Non-GAAP ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" for an explanation of composition.
(3) Shares outstanding are presented net of shares held in trust.

At December 31, 2022, Perpetual had total net debt of $56.3 million, down $2.9 million (5%) from December 31, 2021 as adjusted funds flow exceeded capital expenditures during 2022. The majority of Perpetual's planned 2022 capital spending at East Edson and Mannville was executed during the third quarter, with production additions gradually contributing to sales volumes by late September. By December 31, 2022, increased free funds flows related to increased sales volumes combined with limited additional capital spending during the fourth quarter which reduced net debt.

Perpetual had available liquidity at December 31, 2022 of $13.9 million, comprised of the $30.0 million Credit Facility Borrowing Limit, less current borrowings and letters of credit of $14.9 million and $1.2 million, respectively.

Revolving bank debt

The Company has a first lien credit facility of $30.0 million (December 31, 2021 - $17 million) with an initial term to May 31, 2023. The initial term may be extended to May 31, 2024 subject to approval by the syndicate. If the facility is not extended all outstanding balances would be repayable on May 31, 2024. The next semi-annual borrowing base redetermination is scheduled to be completed on or before May 31, 2023.

As at December 31, 2022, $14.9 million was drawn (December 31, 2021 – $2.5 million) and $1.2 million of letters of credit had been issued (December 31, 2021 – $1.0 million) under the Company's credit facility. Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 3.0% and 5.5%. The effective interest rate on the Credit Facility at December 31, 2022 was 7.9%. For the year ended December 31, 2022 if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net income would be $0.1 million.

The Credit Facility is secured by general first lien security agreements covering all present and future property of the Company and its subsidiaries.

At December 31, 2022, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

($ thousands,			December 31, 2022		December 31, 2021	
except as noted)	**Maturity date**	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	December 31, 2024	8.1%	**2,671**	**2,524**	2,671	2,469

During the third quarter of 2021, Perpetual executed an agreement with its Term Loan lender for the settlement of principal and all interest owing on the Term Loan. Perpetual substantively modified the previous Term Loan with Alberta Investment Management Corporation ("AIMCo") in exchange for the payment of approximately $38.5 million in cash, the delivery by Perpetual of the AIMCo Bonus Shares at a value of $1.4 million, the issuance of a new $2.7 million second lien Term Loan (the "New Term Loan"), and up to an aggregate $4.5 million in contingent payments over the three year period ended June 30, 2024 in the event that Perpetual's annual average realized oil and natural gas prices exceed certain thresholds (the "Second Lien Loan Settlement"). All amounts related to the Second Lien Loan Settlement were paid on October 5, 2021. The New Term Loan bears interest at 8.1% annually, which Perpetual may elect to pay-in-kind and will mature on December 31, 2024. Perpetual has the ability to repay the Term Loan at any time without any repayment penalty.

The Company and the Term Loan lender agreed to allow $1.8 million of interest due December 31, 2020 to be paid-in-kind and added to the outstanding principal amount of the loan and all other interest owing on the Term Loan to be settled as part of the Second Lien Loan Settlement. Non-cash paid-in-kind interest of $0.8 million was recorded in the third quarter of 2021, which increased the principal amount of the Term Loan owing upon settlement to $49.6 million. As a result of the Second Lien Loan Settlement, the carrying amount of $49.6 million was in excess of the consideration received of $42.8 million, resulting in a gain of $6.8 million being recognized (note 20).

The New Term Loan has a cross-default provision with the Credit Facility and contains substantially similar provisions and covenants as the Credit Facility. The Term Loan is secured by a general security agreement over all present and future property of the Company and its subsidiaries on a second priority basis, subordinate only to liens securing loans under the Credit Facility.

At December 31, 2022, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

($ thousands, except as noted)	Maturity date	Interest rate	December 31, 2022 Principal	December 31, 2022 Carrying Amount	December 31, 2021 Principal	December 31, 2021 Carrying amount
Senior notes	January 23, 2025	8.75%	**35,647**	**34,527**	36,583	34,189

On January 22, 2021, Perpetual announced the completion of a Court-approved plan of arrangement whereby the unsecured 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025. The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in cash, or in additional 2025 Senior Notes (a "PIK Interest Payment"). In 2021, the Company elected to pay the semi-annual interest payments by making PIK Interest Payments, increasing the principal amount to $36.6 million.

The Company satisfied the January 23, 2022 and the July 23, 2022 semi-annual interest payment of $1.6 million by making cash payments. Subsequent to December 31, 2022 the Company satisfied the January 23, 2023 semi-annual interest of $1.6 million by making a cash payment.

At December 31, 2022, the senior notes are recorded at the present value of future cash flows, net of $1.1 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.9%.

During the fourth quarter of 2022 the Company purchased and cancelled a portion of the 2025 Senior Notes balance with a carrying value of $0.9 million (2021 - nil) for gross proceeds of $0.8 million. A gain on extinguishment of $0.1 million (2021 - nil) is included in non-cash finance expense.

The senior notes are direct senior secured, third lien obligations of the Company. The Company may redeem the senior notes without any repayment penalty. The senior notes have a cross-default provision with the Company's Credit Facility. In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt, and stock repurchases.

At December 31, 2022, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Entities controlled by the Company's CEO hold $15.9 million of the 2025 Senior Notes outstanding. An entity that is associated with the Company's CEO holds an additional $10.3 million of the 2025 Senior Notes outstanding.

Equity

At December 31, 2022, there were 65.9 million common shares outstanding, net of 1.3 million shares held in trust to resource employee compensation programs. During the fourth quarter of 2022, 0.1 million shares were purchased by the independent trustee to be held in trust (Q4 2021 – 0.2 million). Basic and diluted weighted average shares outstanding for the three months ended December 31, 2022 were 65.9 million and 75.1 million, respectively (Q4 2021 - 63.6 million basic and 70.0 million diluted). Basic and diluted weighted average shares outstanding for the twelve months ended December 31, 2022 were 64.4 million and 74.8 million, respectively (2021 - 63.0 million basic and 70.0 million diluted).

At March 2, 2023, there were 65.9 million common shares outstanding which is net of 1.3 million shares held in trust for employee compensation programs. In addition, the following potentially issuable common shares were outstanding as at the date of this MD&A:

(millions)	March 2, 2023
Share options	**3.6**
Performance share rights	**2.5**
Compensation awards	**8.7**
Total(1)	**14.8**

(1) 7.4 million compensation awards, 2.3 million share options, and 2.5 million performance share rights have an exercise price below the December 31, 2022 closing price of the Company's common shares of $0.71 per share.

Commodity price risk management and sales obligations

Perpetual's commodity price risk management strategy is focused on managing downside risk and increasing certainty in adjusted funds flow by mitigating the effect of commodity price volatility. Physical forward sales contracts and financial derivatives are used to increase certainty in adjusted funds flow (see "Non-GAAP and Other Financial Measures"), manage the balance sheet, lock in economics on capital programs, and to take advantage of perceived anomalies in commodity markets. Perpetual also utilizes foreign exchange derivatives and physical or financial derivatives related to the differential between natural gas prices at the AECO and NYMEX trading hubs and oil basis differentials between WTI and WCS in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's revenue. Diversification of markets is a further risk management strategy employed by the Company.

As at March 2, 2023, the Company had entered into the following swap commodity contracts:

Commodity	Volumes sold	Term	Reference/ Index	Contract Traded Bought/sold	Market Price
Natural gas	5,000 GJ/d	Jan 1 - Mar 31, 2023	AECO 5A (CAD$/GJ)	Swap - sold	$4.62
Natural gas	5,000 GJ/d	Jan 1 - Mar 31, 2023	AECO 7A (CAD$/GJ)	Collar - sold	$7.00-8.00
Natural gas	10,000 GJ/d	Jan 1 - Mar 31, 2023	AECO 7A (CAD$/GJ)	Collar - sold	$7.00-8.10
Natural gas	5,000 GJ/d	Mar 1 - Mar 31, 2023	AECO 7A (CAD$/GJ)	Collar - bought	$3.95
Crude Oil	100 bbl/d	Jan 1 – Dec 31, 2023	WTI (USD$/bbl)	Swap – sold	$89.15
Natural gas	2,500 GJ/d	Mar 1 - Mar 31, 2023	AECO 7A (CAD$/GJ)	Swap - bought	$3.55
Crude oil	200 bbl/d	Apr 1 - Dec 31, 2023	WTI (USD$/bbl)	Swap – sold	$77.40

As at March 2, 2023, the Company had entered into the following swap WTI-WCS basis differential which settle in CAD$:

Commodity	Volumes sold	Term	Reference/ Index	Contract Traded Bought/sold	Market Price
Crude oil	100 bbl/d	Jan 1 – Dec 31, 2023	WCS (CAD$/bbl)	Differential	($17.30)
Crude oil	450 bbl/d	Apr 1 - Dec 31, 2023	WCS (USD$/bbl)	Differential	($17.43)
Crude oil	100 bbl/d	Jul 1 - Dec 31, 2023	WCS (USD$/bbl)	Differential	($16.20)
Crude oil	250 bbl/d	Jan 1, 2024 - Dec 31, 2024	WCS (USD$/bbl)	Differential	($17.50)

As at March 2, 2023, the Company had entered the following CAD/USD foreign exchange swaps which settle in CAD$:

Contract	Notional amount	Term	Price (US$/CAD$)
Average rate forward (US$/CAD$)	$316,444 US$/month	Jan 1 – Mar 31, 2023	1.3740
Average rate forward (US$/CAD$)	$500,000 US$/month	Jan 1 – Dec 31, 2023	1.3710
Average rate forward (US$/CAD$)	$200,000 US$/month	Jan 1 – Dec 31, 2023	1.3029
Average rate forward (US$/CAD$)	$250,000 US$/month	Jan 1 – Dec 31, 2023	1.3600

Conventional natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations and priced at daily index prices at each of the market price points, less transportation costs from AECO to each market price point as detailed below.

Market/Pricing Point	January 1, 2023 to October 31, 2023 Daily sales volume (MMBtu/d)	November 1, 2023 to October 31, 2024 Daily sales volume (MMBtu/d)
Malin	—	15,000
Dawn	15,000	15,000
Emerson	10,000	10,000
Total sales volume obligation	**25,000**	**40,000**

SEQUOIA LITIGATION UPDATE

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy (the "Trustee") of Sequoia Resources Corp. ("Sequoia"), with the Alberta Court of Queen's Bench (the "Court"), against Perpetual (the "Sequoia Litigation"). The claim relates to a six-year-old transaction when, on October 1, 2016, Perpetual closed the disposition of shallow conventional natural gas assets in Eastern Alberta to an arm's length third party at fair market value after an extensive and lengthy marketing, due diligence, and negotiation process (the "Sequoia Disposition"). This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and applications to the Court to dismiss all claims has been made on the basis that there is no merit to any of them.

On January 13, 2020, a written decision related to the Application for Dismissal, dismissed and struck all claims against the Company's CEO and all but one of the claims filed against Perpetual. The Court did not find that the test for summary dismissal relating to whether the asset transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim could continue against Perpetual. The Trustee filed a notice of appeal with the Court of Appeal of Alberta, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal"). The First Appeal proceedings were heard on December 10, 2020. On January 25, 2021, the Court of Appeal of Alberta issued their judgement with respect to the First Appeal proceedings, dismissing the appeal filed by Perpetual and granting certain aspects of the appeals filed by the Trustee, thereby reinstating certain elements of the Sequoia Litigation for trial. On March 24, 2021, Perpetual applied for leave to appeal the First Appeal decision to the Supreme Court of Canada (the "SCC"). On July 8, 2021, the SCC dismissed Perpetual's application.

On February 25, 2020, Perpetual filed a second application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the asset transaction nor caused to be insolvent by the asset transaction (the "Second Summary Dismissal Application"). In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the Second Summary Dismissal Application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1 and 2, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings. On January 14, 2021 the Court issued its decision, finding that the Trustee could not establish a necessary element of the BIA Claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded there is "no merit" to the BIA Claim and it summarily dismissed the balance of the Statement of Claim. The Trustee appealed this decision, and the Court of Appeal hearing took place on February 10, 2022, with the panel reserving judgement. On March 25, 2022, the Court of Appeal issued their judgement with respect to this matter and allowed PwC's appeal on the basis that the Court of Queen's Bench erred in law in its handling of the end-of-life obligations and that based on the record, it could not be concluded the error was without consequence, and that the Court of Queen's Bench also erred in agreeing to hear the Second Summary Dismissal Application. On this basis, the BIA Claim has been directed to trial.

The Trustee filed its Amended Statement of Claim with the Court on October 14, 2022. Perpetual filed its Statement of Defence to Amended Statement of Claim on December 12, 2022.

Management expects that the Company is more likely than not to be completely successful in defending against the Sequoia Litigation such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in these financial statements.

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

($ thousands, except as noted)	**2022**	2021	2020
Financial			
Oil and natural gas revenue	**109,687**	60,814	29,486
Net income	**44,397**	81,121	(61,597)
Per share – basic	**0.69**	1.29	(1.01)
Per share – diluted	**0.59**	1.16	(1.01)
Cash flow from operating activities	**37,830**	12,815	(9,533)
Adjusted funds flow(1)	**48,471**	16,746	(7,787)
Per share – basic(2)	**0.75**	0.27	(0.13)
Revolving bank debt	**14,909**	2,487	17,495
Senior notes, principal amount	**35,647**	36,582	33,580
Term loan, principal amount	**2,671**	2,671	46,823
Other Liability	**3,342**	1,387	—
Net working capital deficiency	**(220)**	16,143	7,099
Total Net Debt	**56,349**	59,270	104,997
Capital expenditures(1)	**31,909**	19,062	5,939
Net payments (proceeds) on acquisitions and dispositions(1)	**—**	49,549	27,754
Common shares (thousands)			
Weighted average – basic	**64,448**	62,969	61,013
Weighted average – diluted	**74,798**	69,989	61,013
Operating			
Daily average production			
Natural gas *(MMcf/d)*	**31.0**	24.6	21.5
Oil *(bbl/d)*	**898**	963	1,082
NGL *(bbl/d)*	**416**	331	346
Total (boe/d)	**6,486**	5,389	5,012
Perpetual Average Realized Prices(2)			
Natural gas *($/Mcf)*	**5.90**	3.15	0.85
Oil *($/bbl)*	**90.15**	57.36	49.37
NGL *($/bbl)*	**88.05**	63.24	31.40
Wells drilled			
Conventional natural gas - gross (net)	**7 (3.5)**	9 (4.5)	5 (2.5)
Heavy crude oil - gross (net)	**5 (5.0)**	5 (4.0)	4 (4.0)
Total - gross (net)	**12 (8.5)**	14 (8.5)	9 (6.5)

(1) Non-GAAP measure. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.
(2) Non-GAAP ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2022**	Q3 2022	Q2 2022	Q1 2022
Financial				
Oil and natural gas revenue	**28,579**	22,856	33,299	24,953
Net income	**9,264**	8,234	4,470	7,162
Per share – basic	**0.14**	0.13	0.07	0.11
Per share – diluted	**0.12**	0.11	0.06	0.10
Cash flow from operating activities	**8,749**	8,749	11,571	6,272
Adjusted funds flow[1]	**14,207**	9,642	10,505	14,117
Per share – basic[2]	**0.22**	0.15	0.16	0.22
Capital expenditures[1]	**115**	22,596	4,361	4,837
Net payments (proceeds) on acquisitions and dispositions[1]	**—**	—	—	—
Common shares (thousands)				
Weighted average – basic	**65,883**	65,016	63,641	63,216
Weighted average – diluted	**75,090**	74,607	74,721	74,348
Operating				
Daily average production				
Natural gas (MMcf/d)	**33.0**	26.9	29.9	34.3
Oil (bbl/d)	**1,126**	1,002	775	682
NGL (bbl/d)	**508**	390	364	400
Total (boe/d)	**7,138**	5,882	6,123	6,804
Perpetual Average Realized Prices[2]				
Natural gas ($/mcf)	**5.78**	4.74	7.92	5.16
Oil ($/bbl)	**71.14**	87.24	117.20	95.55
NGL ($/bbl)	**78.36**	85.48	104.71	87.86

($ thousands, except as noted)	Q4 2021	Q3 2021	Q2 2021	Q1 2021
Financial				
Oil and natural gas revenue	21,449	14,603	13,226	11,536
Net income	5,669	51,151	27,017	(2,706)
Per share – basic	0.09	0.80	0.43	(0.04)
Per share – diluted	0.08	0.72	0.38	(0.04)
Cash flow from operating activities	1,624	6,655	2,854	1,682
Adjusted funds flow[1]	8,585	3,315	2,302	2,544
Per share – basic[2]	0.13	0.05	0.04	0.04
Capital expenditures[1]	7,558	9,947	1,554	3
Net payments (proceeds) on acquisitions and dispositions[1]	53,407	(4,060)	46	469
Common shares (thousands)				
Weighted average – basic	63,853	63,801	62,574	61,603
Weighted average – diluted	70,873	71,266	70,461	61,603
Operating				
Daily average production				
Natural gas (MMcf/d)	31.5	21.6	22.2	22.9
Oil (bbl/d)	714	972	1,074	1,097
NGL (bbl/d)	395	300	331	294
Total (boe/d)	6,359	4,876	5,099	5,211
Perpetual Average Realized Prices[2]				
Natural gas ($/Mcf)	4.80	2.59	2.25	2.25
Oil ($/bbl)	73.93	65.19	55.75	40.85
NGL ($/bbl)	73.44	65.37	55.48	56.03

(1) Non-GAAP measure. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.
(2) Non-GAAP ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this MD&A and in other materials disclosed by the Company, Perpetual employs certain measures to analyze financial performance, financial position and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from operating activities, and cash flow from investing activities, as indicators of Perpetual's performance.

Non-GAAP Financial Measures

Capital expenditures or capital spending: Perpetual uses capital expenditures or capital spending related to exploration and development to measure its capital investments compared to the Company's annual capital budgeted expenditures. Perpetual's capital budget excludes acquisition and disposition activities.

The most directly comparable GAAP measure for capital expenditures or capital spending is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures or capital spending, is set forth below:

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands)	**2022**	2021	**2022**	2021
Net cash flows used in investing activities	**17,239**	(49,217)	**40,941**	(43,725)
Acquisitions	**—**	(700)	**—**	(1,325)
Net proceeds on dispositions, net of cash disposed	**—**	53,407	**—**	49,549
Purchase of marketable securities	**(2)**	—	**(39)**	—
Change in non-cash working capital	**(17,122)**	4,068	**(8,993)**	14,563
Capital expenditures	**115**	7,558	**31,909**	19,062

Adjusted funds flow: Adjusted funds flow is calculated based on cash flows from (used in) operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow and regulatory requirements. The Company has added back non-cash oil and natural gas revenue in-kind, equal to retained East Edson royalty obligation payments taken in-kind, to present the equivalent amount of cash revenue generated. Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations, and meet its financial obligations.

Adjusted funds flow is not intended to represent net cash flows from (used in) operating activities calculated in accordance with IFRS.

The following table reconciles net cash flows from (used in) operating activities as reported in the Company's consolidated statements of cash flows, to adjusted funds flow:

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except per share and per boe amounts)	**2022**	2021	**2022**	2021
Net cash flows from operating activities	**11,238**	1,624	**37,830**	12,815
Change in non-cash working capital	**1,925**	4,197	**9,442**	(3,406)
Decommissioning obligations settled (cash)	**1,044**	1,382	**1,199**	1,759
Oil and natural gas revenue in-kind	**—**	1,382	**—**	4,995
Payment of restructuring costs	**—**	—	**—**	583
Adjusted funds flow	**14,207**	8,585	**48,471**	16,746
Adjusted funds flow per share	**0.22**	0.13	**0.75**	0.27
Adjusted funds flow per boe	**21.63**	14.67	**20.48**	8.51

Free funds flow: Free funds flow is an important measure that informs efficiency of capital spent and liquidity. Free funds flow is calculated as adjusted funds flow generated during the period less capital expenditures. Adjusted funds flow and capital expenditures are non-GAAP financial measures which have been reconciled to its most directly comparable GAAP measure previously in this document. By removing the impact of current period capital expenditures from adjusted funds flow, Perpetual monitors its free funds flow to inform decisions such as capital allocation and debt repayment.

The following table shows the calculation of the removal of capital expenditures from adjusted funds flows:

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except per share and per boe amounts)	**2022**	2021	**2022**	2021
Adjusted funds flow	**14,207**	8,585	**48,471**	16,746
Capital Expenditures	**(115)**	(7,558)	**(31,909)**	(19,062)
Free funds flow	**14,092**	1,027	**16,562**	(2,316)

Cash costs: Cash costs are controllable costs comprised of production and operating, transportation, general and administrative, and cash finance expense as detailed below. Cash costs per boe is calculated by dividing cash costs by total production sold in the period. Management believes that cash costs assist management and investors in assessing Perpetual's efficiency and overall cost structure.

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands, except per boe amounts*)	**2022**	2021	**2022**	2021
Production and operating	**3,828**	2,862	**16,107**	12,859
Transportation	**1,223**	871	**3,872**	2,993
General and administrative	**2,855**	3,657	**9,911**	10,757
Cash finance expense	**1,195**	1,039	**4,547**	1,309
Cash costs	**9,101**	8,429	**34,437**	27,919
Cash costs per boe	**13.86**	14.41	**14.55**	14.19

Operating netback: Operating netback is calculated by deducting royalties, production and operating expenses, and transportation costs from oil and natural gas revenue. Operating netback is also calculated on a per boe basis using total production sold in the period and presented before and after realized gains or losses from risk management contracts. Perpetual considers that netback is a key industry performance indicator and one that provides investors with information that is also commonly presented by other crude oil and natural gas producers. Perpetual considers operating netback to be an important performance measure to evaluate its operational performance as it demonstrates its profitability relative to current commodity prices. Refer to reconciliations earlier in the MD&A under the "Operating netbacks" section.

Net Debt: Perpetual uses net debt as an alternative measure of outstanding debt. Management considers net debt as an important measure in assessing the liquidity of the Company. Net debt is used by management to assess the Company's overall debt position and borrowing capacity. Net debt is not a standardized measure and therefore may not be comparable to similar measures presented by other entities.

The following table details the composition of net debt:

(*$ thousands*)	**As of December 31, 2022**	As of December 31, 2021
Cash and cash equivalents	**—**	1,090
Accounts and accrued receivable	**15,804**	11,671
Prepaid expenses and deposits	**1,564**	910
Marketable securities	**1,814**	2,409
Accounts payable and accrued liabilities	**(18,962)**	(32,223)
Adjusted working capital surplus (deficiency)[1]	**220**	(16,143)
Bank indebtedness	**(14,909)**	(2,487)
Term loan (principal)	**(2,671)**	(2,671)
Other liability (undiscounted amount)	**(3,342)**	(1,387)
Senior notes (principal)	**(35,647)**	(36,582)
Net debt	**(56,349)**	(59,270)

(1) Alternative calculation of current assets less current liabilities adjusted for the removal of the current portion of risk management contracts.

Available Liquidity: Available Liquidity is defined as Perpetual's Credit Facility Borrowing Limit, less current borrowings and letters of credit issued under the Credit Facility. Management uses available liquidity to assess the ability of the Company to finance capital expenditures and expenditures on decommissioning obligations, and to meet its financial obligations.

Enterprise value: Enterprise value is equal to net debt plus the market value of issued equity and is used by management to analyze leverage. Enterprise value is calculated by multiplying the current shares outstanding by the market price at the end of the period and then adjusting it by the net debt. The Company considers enterprise value as an important measure as it normalizes the market value of the Company's shares for its capital structure.

Non-GAAP Financial Ratios

Perpetual calculates certain non-GAAP measures per boe as the measure divided by weighted average daily production. Management believes that per boe ratios are a key industry performance measure of operational efficiency and one that provides investors with information that is also commonly presented by other crude oil and natural gas producers. Perpetual also calculates certain non-GAAP measures per share as the measure divided by outstanding common shares.

Average realized prices after risk management contracts: are calculated as the average realized price by product type less the realized gain or loss on risk management contracts by production type.

Net debt to adjusted funds flow ratio: Net debt to adjusted funds flow ratios are calculated on a trailing twelve-month basis.

Net debt as a percentage of enterprise value: Net debt as a percentage of enterprise value is calculated by dividing net debt by enterprise value.

Adjusted funds flow per share: Adjusted funds flow ratios are calculated on a per share as the measure divided by basic shares outstanding.

Adjusted funds flow per boe: Adjusted funds flow per boe is calculated as adjusted funds flow divided by total production sold in the period.

Supplementary Financial Measures

"Average realized price" is comprised of total commodity sales from production, as determined in accordance with IFRS, divided by the Company's total sales producution on a boe basis.

"Realized oil price" is comprised of oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's oil sales production.

"Realized natural gas price" is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas sales production.

"Realized NGL price" is comprised of NGL commodity sales from production, as determined in accordance with IFRS, divided by the Company's NGL sales production.

"Realized gain (loss) on natural gas contracts per mcf" is comprised of the realized gain or loss on natural gas contracts, as determined in accordance with IFRS, divided by the Company's total natural gas sales production.

"Realized gain (loss) on oil contracts per boe" is comprised of the realized gain or loss on oil contracts, as determined in accordance with IFRS, divided by the Company's total oil sales production.

"Realized gain (loss) on risk management contracts per boe" is comprised of the realized gain or loss on risk management contracts, as determined in accordance with IFRS, divided by the Company's total sales production.

"Depletion and depreciation expense per boe" is comprised of DD&A expense, as determined in accordance with IFRS, divided by the Company's total sales production.

"G&A expense per boe" is comprised of G&A expense, as determined in accordance with IFRS, divided by the Company's total sales production.

"Operating expense per boe" is comprised of operating expense, as determined in accordance with IFRS, divided by the Company's total sales production.

"Realized gain or loss on risk management contract per boe" is comprised of realized gain on risk management contracts, as determined in accordance with IFRS, divided by the Company's total sales production.

"Transportation expense per boe" is comprised of operating expense, as determined in accordance with IFRS, divided by the Company's total sales production.

"Royalties as a percentage of revenue" is comprised of royalties, as determined in accordance with IFRS, divided by oil and natural gas revenue from sales production as determined in accordance with IFRS.

"Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total sales production.

"Market value of shares" is comprised of common shares outstanding multiplied by the market price of shares.

"Adjusted funds flow per share" is comprised of adjusted funds flow divided by the Company's shares outstanding.

FUTURE ACCOUNTING PRONOUNCEMENTS

The International Accounting Standards Board ("IASB") and the IFRS Interpretations Committee regularly issue new and revised accounting pronouncements which have future effective dates and therefore are not reflected in Perpetual's financial statements. Once adopted, these new and amended pronouncements may have an impact on Perpetual's consolidated financial statements. Perpetual's analysis of recent accounting pronouncements is included in the notes to the consolidated financial statements at December 31, 2022.

RISK FACTORS

The Corporation is exposed to business risks that are inherent in the oil and gas industry, as well as those governed by the individual nature of Perpetual's operations. Risks impacting the business which influence controls and management of the Corporation include, but are not limited to, the following:

- geological and engineering risks;
- the uncertainty of discovering commercial quantities of new reserves;
- commodity prices, interest rate and foreign exchange risks;
- political and geopolitical risks;
- competition
- cybersecurity risks;
- inflation and supply chain risks;
- risks relating to pandemics (including COVID-19);
- risks relating to litigation (including the Sequoia litigation); and
- changes to government regulations including royalty regimes and tax legislation.

Perpetual manages these risks by:

- attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Corporation;
- prudent operation of oil and natural gas properties;
- employing risk management instruments and policies to manage exposure to volatility of commodity prices, interest rates and foreign exchange rates;
- maintaining a flexible financial position;
- maintaining strict environmental, safety and health practices; and
- active participation with industry organizations to monitor and influence changes in government regulations and policies.

A complete discussion of risk factors is included in the Corporation's 2022 Annual Information Form ("AIF") available on the Corporation's website at www.perpetualenergyinc.com or on SEDAR at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Perpetual's CEO and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICOFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS.

Disclosure controls and procedures

The DC&P have been designed to provide reasonable assurance that material information relating to Perpetual is made known to the CEO and CFO by others, and that information required to be disclosed by Perpetual in its annual filings, interim filing or other reports is filed or submitted by Perpetual under securities legislation.

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2022, the DC&P are designed and operating effectively to provide reasonable assurance that information required to be disclosed by the Corporation 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 periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Management's annual report on internal controls over financial reporting

Management is responsible for establishing and maintaining adequate ICOFR, which is a process designed by, or under the supervision of, the CEO and CFO, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal controls over financial reporting was conducted as of December 31, 2022 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2022, the internal controls over financial reporting were designed and operating effectively.

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

There were no changes in the Corporation's internal control over financial reporting during the period beginning on October 1, 2022 and ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

CEO and CFO certifications

Perpetual's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Perpetual's public disclosures relating to its fiscal 2022 filings with the Canadian securities regulators.

CRITICAL ACCOUNTING JUDGEMENTS AND ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates.

Perpetual's financial and operational results incorporate certain estimates including:

- estimated commodity sales from production at a specific reporting date for which actual revenues have not yet been received, including associated estimated credit losses;
- estimated royalty obligations, transportation, and operating expenses at a specific reporting date for which costs have been incurred but have not yet been settled;
- estimated capital expenditures on projects that are in progress;
- estimated depletion charges and deferred tax assets that are based on estimates of reserves that Perpetual expects to recover in the future;
- estimated future recoverable value of PP&E and E&E and any associated impairment charges or reversals;
- estimated fair values of financial instruments that are subject to fluctuation depending upon the underlying forward curves for commodity prices, foreign exchange rates and interest rates, as well as volatility curves, and the risk of non-performance;
- estimated value of ARO that is dependent upon estimates of future costs and timing of expenditures;
- estimated compensation expense under Perpetual's share-based compensation plans including the PSUs awarded under the PSU Plans that are dependent on the final number of PSU awards that eventually vest based on a performance multiplier; and
- estimated fair values of assets acquired and liabilities assumed in a business combination.

A change in a critical accounting estimate can have a significant effect on net loss, including their impact on the depletion rate, provisions, impairments, and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2022.

FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain information in this MD&A including management's assessment of future plans and operations, and including the information contained under the heading "2023 Outlook" may constitute forward-looking information or statements (together "forward-looking information") under applicable securities laws. The forward-looking information includes, without limitation, statements with respect to: forecast production and exploration and development capital expenditures for 2023 and the expectation that such expenditures will be funded from adjusted funds flow; drilling activities for 2023 including the number of gross and net wells to be drilled; cash costs estimates; projected abandonment and reclamation expenditures and the funding thereof; expectations as to drilling activity plans in various areas and the benefits to be derived from such drilling including the production growth and expectations respecting Perpetual's future exploration, development and drilling activities; and Perpetual's business plan.

Forward-looking information is based on current expectations, estimates and projections that involve a number of known and unknown risks, which could cause actual results to vary and in some instances to differ materially from those anticipated by Perpetual and described in the forward-looking information contained in this MD&A. In particular and without limitation of the foregoing, material factors or assumptions on which the forward-looking information in this MD&A is based include: forecast commodity prices and other pricing assumptions; forecast production volumes based on business and market conditions; foreign exchange and interest rates; near-term pricing and continued volatility of the market including inflationary pressures; accounting estimates and judgments; future use and development of technology and associated expected future results; the ability to obtain regulatory approvals; the successful and timely implementation of capital projects; ability to generate sufficient cash flow to meet current and future obligations; the ability of Perpetual to obtain and retain qualified staff and equipment in a timely and cost-efficient manner, as applicable; the retention of key properties; forecast inflation, supply chain access and other assumptions inherent in Perpetual's current guidance and estimates; the continuance of existing tax, royalty, and regulatory regimes; the accuracy of the estimates of reserves volumes; ability to access and implement technology necessary to efficiently and effectively operate assets; and the ongoing and future impact of the coronavirus and the war in Ukraine and related sanctions on commodity prices and the global economy, among others.

Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in Perpetual's Annual Information Form and MD&A for the year ended December 31, 2022 and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com) and at Perpetual's website (www.perpetualenergyinc.com). Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Perpetual's management at the time the information is released, and Perpetual disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

GLOSSARY

The following is a list of abbreviations that may be used in this MD&A:

Measurement:

bbl	barrel
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
boe(1)	barrels of oil equivalent
boe/d(1)	barrels of oil equivalent per day
Mboe(1)	thousands of barrels of oil equivalent
MMboe(1)	millions of barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMBtu	million British thermal units
GJ	gigajoule

Volume Conversions:

Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for conventional natural gas of 6 Mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between conventional natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl. A conversion ratio of 1 bbl of heavy crude oil to 1 bbl of NGL has also been used throughout this MD&A. " See "Fourth Quarter Financial and Operating Results" section in this MD&A for details of constituent product components that comprise Perpetual's boe production.

Financial and Business Environment:

AECO	Alberta Energy Company
DD&A	Depletion, depreciation and amortization
E&E	Exploration and evaluation
GAAP	Generally accepted accounting principles
G&A	General and administrative
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange,
PP&E	Property, plant and equipment
WTI	West Texas Intermediate

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

The consolidated financial statements of Perpetual Energy Inc. ("Perpetual" or the "Company") are the responsibility of Management and have been approved by the Board of Directors of the Company. These consolidated financial statements have been prepared by Management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and the Interpretations of the IFRS Interpretations Committee.

The consolidated financial statements are audited and have been prepared using accounting policies in accordance with IFRS. The preparation of Management's Discussion and Analysis is based on the Company's financial results which have been prepared in accordance with IFRS. It compares the Company's financial performance in 2022 to 2021 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management believes that the system of internal controls that have been designed and maintained at the Company provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements. The internal accounting control process includes Management's communication to employees of policies which govern ethical business conduct.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Board of Directors has appointed an Audit Committee consisting of unrelated, non-management directors which meets during the year with Management and independently with the external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the charter of the Audit Committee as set out in the Annual Information Form. The Audit Committee reviews the consolidated financial statements and Management's Discussion and Analysis before the consolidated financial statements are submitted to the Board of Directors for approval. The external auditors have free access to the Audit Committee without obtaining prior Management approval.

With respect to the external auditors, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The independent external auditors, KPMG LLP, have been appointed by the Board of Directors on behalf of the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, financial performance and cash flows in accordance with IFRS. The report of KPMG LLP outlines the scope of their examination and their opinion on the consolidated financial statements.

Susan Riddell Rose

Susan L. Riddell Rose
President & Chief Executive Officer

Ryan Shay

Ryan A. Shay
Vice President, Finance & Chief Financial Officer

March 2, 2023

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Perpetual Energy Inc.

Opinion

We have audited the consolidated financial statements of Perpetual Energy Inc. (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2022 and December 31, 2021
- the consolidated statements of income and comprehensive income for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

Hereinafter referred to as the "financial statements".

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2022 and December 31, 2021, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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 **"*Auditors' Responsibilities for the Audit of the Financial Statements*"** section of our auditors' report.

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

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

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2022. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Assessment of the impact of estimated proved and probable oil and gas reserves on property, plant and equipment ("PP&E") and the deferred tax asset ("DTA")

Description of the matter

We draw attention to note 2, note 3, note 5 and note 23 to the financial statements. The Company uses estimated proved and probable oil and gas reserves to deplete its development and production assets included in PP&E, to assess for indicators of impairment or impairment reversal on each of the Company's cash generating units ("CGU") and if any such indicators exist, to perform an impairment test to estimate the recoverable amount of a CGU and to determine if it is probable that future taxable profits will be sufficient to utilize the underlying deductible temporary differences and unused tax losses associated with the DTA.

The Company has $170.6 million of PP&E as at December 31, 2022.

The Company identified an indicator of impairment reversal at March 31, 2022 for the Eastern Alberta CGU and performed an impairment reversal test to estimate the recoverable amount of the CGU. It was determined the recoverable amount of the Eastern Alberta CGU exceeded the CGU's carrying value, resulting in all previous Eastern Alberta CGU impairment, net of depletion, of $7.4 million being reversed.

The estimated recoverable amount of the Eastern Alberta CGU involves significant estimates including:

- The estimate of proved and probable oil and gas reserves
- The discount rates.

The Company depletes its net carrying value of development and production assets using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable oil and gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. Depletion expense on development and production assets was $17.8 million for the year ended December 31, 2022.

The Company recognized a DTA of $15.9 million at December 31, 2022. The determination of probable future taxable profits involves significant estimates, including proved and probable oil and gas reserves.

The estimated proved and probable oil and gas reserves includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production volumes
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs.

The Company engages independent third party reserve evaluators to estimate proved and probable oil and gas reserves. For purposes of the March 31, 2022 impairment test, the Company's internal reserve evaluators updated the significant assumptions from the independent third party reserve evaluators estimate of proved and probable oil and gas reserves as at December 31, 2021.

Why the matter is a key audit matter

We identified the assessment of the impact of estimated proved and probable oil and gas reserves on PP&E and the DTA as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and gas reserves and discount rates. Additionally, the assessment of the recoverable amounts of a CGU and the measurement of the DTA requires the use of professionals with specialized skills and knowledge in valuation and tax.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

We examined management's impairment reversal test for the Eastern Alberta CGU as at March 31, 2022 by comparing amounts to the underlying source documents and performing recalculations.

With respect to the estimate of proved and probable oil and gas reserves as at December 31, 2021 for purposes of the March 31, 2022 impairment test:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve evaluators engaged by the Company
- We compared forecasted oil and gas commodity prices to those published by other independent third party reserve evaluators
- We compared the 2021 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and gas reserves to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2021 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

With respect to the estimate of proved and probable oil and gas reserves as at March 31, 2022 for purposes of the March 31, 2022 impairment test:

- We evaluated the competence, capabilities and objectivity of the internal reserve evaluators
- We compared forecasted oil and gas commodity prices to those published by other independent third party reserve evaluators
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to corresponding amounts in the proved and probable oil and gas reserves estimated by the independent third party reserve evaluators as at December 31, 2021 and by comparing to 2022 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- Evaluating the appropriateness of the Eastern Alberta CGU discount rate by comparing the discount rate to market and other external data
- Assessing the reasonableness of the Company's estimate of the recoverable amount of the Eastern Alberta CGU by comparing the Company's estimate to market metrics and other external data.

We assessed the depletion expense calculation and measurement of the DTA for compliance with IFRS as issued by the IASB.

With respect to the estimate of proved and probable oil and gas reserves as at December 31, 2022 for purposes of depletion and the DTA:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve evaluators engaged by the Company
- We compared forecasted oil and gas commodity prices to those published by other independent third party reserve evaluators
- We compared the 2022 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and gas reserves to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2022 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved income tax professionals with specialized skills and knowledge who assisted in evaluating the application of relevant tax laws and regulations and the appropriateness of the Company's estimate of future taxable profits used in the measurement of the DTA.

Other Information

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

- the information included in Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditor’s report thereon, included in a document likely to be entitled “2022 Annual Results”.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors’ report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors’ report.

We have nothing to report in this regard.

The information, other than the financial statements and the auditor’s report thereon, included in a document likely to be entitled “2022 Annual Results” is expected to be made available to us after the date of this auditor’s report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

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

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

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

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

KPMG

Auditors’ Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors’ 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 the 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 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 auditors’ report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors’ report. However, future events or conditions may cause the Company to cease to continue as a going concern.

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

KPMG

- 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.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' 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 auditors' 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 auditors' report is Gregory Ronald Caldwell.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 2, 2023

PERPETUAL ENERGY INC.
Consolidated Statements of Financial Position

As at		December 31, 2022		December 31, 2021
(Cdn$ thousands)				
Assets				
Current assets				
Cash	**$**	**—**	$	1,090
Accounts receivable		**15,804**		11,671
Marketable securities (note 4, 25)		**1,814**		2,409
Prepaid expenses and deposits		**1,564**		910
Product inventory		**674**		—
Risk management contracts (note 22)		**3,847**		682
		23,703		16,762
Property, plant and equipment (note 5)		**170,644**		153,620
Exploration and evaluation (note 6)		**7,168**		7,329
Right-of-use assets (note 7)		**864**		1,140
Deferred tax asset (note 23)		**15,894**		—
Total assets	**$**	**218,273**	$	178,851
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**18,962**	$	32,223
Other liability (note 11)		**532**		63
Risk management contracts (note 22)		**—**		321
Royalty obligations (note 13)		**—**		4,697
Lease liabilities (note 14)		**705**		778
Decommissioning obligations (note 15)		**1,688**		1,327
		21,887		39,409
Term loan (note 10)		**2,524**		2,469
Revolving bank debt (note 9)		**14,909**		2,487
Other liability (note 11)		**2,470**		1,324
Senior notes (note 12)		**34,527**		34,189
Lease liabilities (note 14)		**870**		1,324
Decommissioning obligations (note 15)		**25,764**		31,600
Total liabilities		**102,951**		112,802
Equity				
Share capital (note 17)		**98,615**		94,809
Contributed surplus		**46,801**		45,731
Deficit		**(30,094)**		(74,491)
Total equity		**115,322**		66,049
Total liabilities and equity	**$**	**218,273**	$	178,851

Contingencies (note 8) & contractual obligations (note 16)

See accompanying notes to the consolidated financial statements.

Linda A. Dietsche
Director

Geoffrey C. Merritt
Director

PERPETUAL ENERGY INC.
Consolidated Statements of Income and Comprehensive Income

(Cdn$ thousands, except per share amounts)		**December 31, 2022**		December 31, 2021
Revenue				
Oil and natural gas (note 19)	**$**	**109,687**	$	60,814
Royalties		**(20,790)**		(9,920)
		88,897		50,894
Unrealized gain risk management contracts (note 22)		**3,487**		3,733
Realized loss risk management contracts (note 22)		**(4,620)**		(4,810)
Gas over bitumen royalty credit		**—**		385
Other income (note 15)		**348**		704
		88,112		50,906
Expenses				
Production and operating		**16,107**		12,859
Transportation		**3,872**		2,993
Exploration and evaluation (note 6)		**118**		120
General and administrative		**9,911**		10,757
Share-based payments (note 18)		**7,434**		2,044
Gain on dispositions (note 5)		**—**		(47,522)
Depletion and depreciation (note 5 and 7)		**17,962**		14,020
Impairment reversal (note 5b)		**(7,400)**		(30,600)
Net income from operating activities		**40,108**		86,235
Finance expense (note 20)		**(10,971)**		(5,396)
Change in fair value of marketable securities (note 4)		**(634)**		282
Net income, before income tax	**$**	**28,503**	$	81,121
Deferred income tax recovery (expense) (note 23)		**15,894**		—
Net income and comprehensive income	**$**	**44,397**	$	81,121
Net income per share (note 17f)				
Basic	**$**	**0.69**	$	1.29
Diluted	**$**	**0.59**	$	1.16

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Changes in Equity

(Cdn$ thousands, except share amounts)	Share capital (thousands)	Share capital ($thousands)	Contributed surplus	Deficit	Total equity
Balance at December 31, 2021	63,567	$ 94,809	$ 45,731	$ (74,491)	$ 66,049
Net income	—	—	—	44,397	$ 44,397
Common shares issued (note 17 and 18)	3,174	4,611	(4,611)	—	$ —
Change in shares held in trust (note 17 and 18)	(797)	(805)	(502)	—	$ (1,307)
Share-based payments (note 18)	—	—	6,183	—	6,183
Balance at December 31, 2022	**65,944**	**$ 98,615**	**$ 46,801**	**$ (30,094)**	**$ 115,322**

(Cdn$ thousands, except share amounts)	Share capital (thousands)	Share capital ($thousands)	Contributed surplus	Deficit	Total equity
Balance at December 31, 2020	61,305	$ 97,333	$ 45,217	$ (155,612)	$ (13,062)
Net income	—	—	—	81,121	81,121
Common shares issued (note 17 and 18)	2,828	473	(284)	—	189
Change in shares held in trust (note 17 and 18)	24	(14)	(49)	—	(63)
Common share split (note 17)	8,158	—	—	—	—
Common share cancellation (note 17)	(8,158)	(2,779)	—	—	(2,779)
Common share odd-lot cancellation (note 17)	(590)	(204)	—	—	(204)
Share-based payments (note 18)	—	—	847	—	847
Balance at December 31, 2021	**63,567**	**$ 94,809**	**$ 45,731**	**$ (74,491)**	**$ 66,049**

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Cash Flows

(Cdn$ thousands)	**December 31, 2022**	December 31, 2021
Cash flows from operating activities		
Net income	**$ 44,397**	$ 81,121
Adjustments to add (deduct) non-cash items:		
Other income (note 15)	**(348)**	(704)
Depletion and depreciation (note 5 and 7)	**17,962**	14,020
Share-based payments (note 18)	**6,183**	360
Deferred income tax recovery (note 23)	**(15,894)**	—
Unrealized gain on risk management contracts (note 22)	**(3,487)**	(3,734)
Change in fair value of marketable securities (note 4)	**634**	(282)
Finance expense (note 20)	**6,424**	4,087
Gain on disposition (note 5)	**—**	(47,522)
Impairment reversal (note 5b)	**(7,400)**	(30,600)
Oil and natural gas revenue in-kind (note 13)	**—**	(4,995)
Transaction costs on disposition (note 5)	**—**	(583)
Decommissioning obligations settled (note 15)	**(1,199)**	(1,759)
Change in non-cash working capital (note 21)	**(9,442)**	3,406
Net cash flows from operating activities	**37,830**	12,815
Cash flows from (used in) financing activities		
Change in revolving bank debt, net of issue costs (note 9)	**11,886**	(15,174)
Change in senior notes, net of issue costs (note 12)	**(834)**	(233)
Change in term loan, net of issue costs (note 10)	**—**	(38,700)
Payments of lease liabilities (note 14)	**(708)**	(620)
Payments of royalties (note 13)	**(6,953)**	(558)
Shares purchased and held in trust (note 17)	**(1,307)**	(395)
Other liability payments (note 11)	**(63)**	—
Common shares issues, net of issue costs	**—**	230
Net cash flows from (used in) financing activities	**2,021**	(55,450)
Cash flows from (used in) investing activities		
Capital expenditures (note 5)	**(31,909)**	(19,062)
Acquisitions (note 5)	**—**	(1,325)
Net proceeds from dispositions (note 5(a))	**—**	49,549
Purchase of marketable securities (note 4)	**(39)**	—
Change in non-cash working capital (note 21)	**(8,993)**	14,563
Net cash flows from (used in) investing activities	**(40,941)**	43,725
Change in cash and cash equivalents	**(1,090)**	1,090
Cash and cash equivalents, beginning of year	**1,090**	—
Cash and cash equivalents, end of year	**$ —**	$ 1,090

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

Perpetual Energy Inc. ("Perpetual" or the "Company") is an oil and natural gas exploration, production, and marketing company headquartered in Calgary, Alberta. Perpetual owns a diversified asset portfolio, including liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, heavy crude oil and shallow conventional natural gas in Eastern Alberta, and undeveloped bitumen leases in Northern Alberta.

The address of the Company's registered office is 3200, 605 – 5 Avenue S.W., Calgary, Alberta, T2P 3H5.

The consolidated financial statements of the Company are comprised of the accounts of Perpetual Energy Inc. and its wholly owned subsidiaries: Perpetual Operating Corp., Perpetual Energy Partnership, and Perpetual Operating Trust, which are incorporated in Alberta.

2. BASIS OF PREPARATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements of the Company were approved and authorized for issue by the Board of Directors on March 2, 2023.

a) Critical accounting judgments and significant estimates

The preparation of the consolidated 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, liabilities, revenue and expenses. These judgments, estimates, and assumptions are continuously evaluated and are based on management's experience and all relevant information available to the Company at the time of financial statement preparation. As the effect of future events cannot be determined with certainty, the actual results may differ from estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about the critical judgments and significant estimates made by management are described below and in the relevant notes to the financial statements.

b) Critical accounting judgments:

The following are the critical judgments that management has made in the process of applying the Company's accounting policies. These judgments have the most significant effect on the amounts reported in the consolidated financial statements.

i) Cash-generating units ("CGUs")

The Company allocates its development and production assets to CGUs, identified as the smallest group of assets that generate cash inflows independent of the cash inflows of other assets or groups of assets. Determination of the CGUs is subject to management's judgement and is based on geographical proximity, shared infrastructure, and similar exposure to market risk.

ii) Identification of impairment indicators

Significant judgment is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. Management considers internal and external sources of information including oil and gas commodity prices, expected production volumes, estimated proved and probable oil and gas reserves and rates used to discount the related future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset or CGU is impaired, or in the case of a previously impaired asset or CGU, whether the carrying amount of the asset or CGU has been restored.

iii) Componentization

For the purposes of depletion, the Company allocates its development and production assets to components with similar useful lives and depletion methods. The grouping of assets is subject to management's judgment and is performed on the basis of geographical proximity and similar reserve life. The Company's oil and gas assets are depleted on a unit-of-production basis.

iv) Exploration and evaluation ("E&E") expenditures

Costs associated with acquiring oil and gas licenses and exploratory drilling are accumulated as exploration and evaluation assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgment and involves management's review of project economics, resource quantities, expected production techniques, production costs and required capital expenditures to develop and extract the underlying resources. Management uses the establishment of commercial reserves within the exploration area as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets attributable to those reserves are tested for impairment and reclassified from E&E assets to a separate category within property, plant and equipment referred to as development and production assets.

v) Joint arrangements

Judgment is required to determine when the Company has joint control over an arrangement. In establishing joint control, the Company considers whether unanimous consent is required to direct the activities that significantly affect the returns of the arrangement, such as the capital and operating activities of the arrangement.

Once joint control has been established, judgment is also required to classify a joint arrangement. The type of joint arrangement is determined through analysis of the rights and obligations arising from the arrangement by considering its structure, legal form, and terms agreed upon by the parties sharing control. An arrangement where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, is classified as a joint operation. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures.

vi) Deferred taxes

Deferred tax assets (if any) are recognized only to the extent it is considered probable that future taxable profits will be sufficient to utilize the underlying deductible temporary differences and unused tax losses associated with the deferred tax asset. This involves an assessment of when those deferred tax assets are likely to reverse and judgment as to whether there will be sufficient taxable profits available to offset the tax assets when they do reverse. The determination of probable future taxable profits involves significant estimates, including proved and probable oil and gas reserves. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

vii) Revenue – principal versus agent

When determining if the Company acted as a principal or as an agent in transactions, management determines if the Company obtains control of the product. As part of this assessment, management considers if the Company obtained control of the goods or services more than momentarily, in advance of transferring those goods or services to the customer. In this assessment, the Company considers indicators that it controlled the goods or services, including whether the Company was primarily responsible for the goods and services, whether the Company had inventory risk and whether the Company had discretion in establishing prices for the goods or services. Where control was indicated, the Company has been determined to be the principal and has recorded revenue and the associated expenses on a gross basis. In other cases, the Company has been determined to be the agent and has recorded revenue net of associated expenses.

c) Significant estimates:

The following assumptions represent the key sources of estimation uncertainty at the end of the reporting period. As future confirming events occur, the actual results may differ from estimated amounts.

i) Reserves

The Company uses estimates of proved and probable oil and gas reserves to deplete its development and production assets included in PP&E, to assess for indicators of impairment or impairment reversal on each of the Company's CGUs and if any such indicators exist, to perform an impairment test to estimate the recoverable amount of a CGU and to determine if it is probable that future taxable profits will be sufficient to utilize the underlying deductible temporary differences and unused tax losses associated with the deferred tax asset. Estimates of proved and probable oil and gas reserves are based upon a number of significant assumptions, such as forecasted production volumes, oil and gas commodity prices, operating costs, royalty costs, and future development costs. Additional estimates are made in relation to the marketability of oil and gas, and the assumed effects of regulation by government agencies. The geological, economic and technical factors used to estimate reserves may change from period to period. Changes in the reported reserves could have a material impact on the carrying values of the Company's development and production assets, the calculation of depletion and depreciation, and the timing of decommissioning expenditures.

The estimate of proved and probable oil and gas reserves are evaluated by independent third party reserve evaluators at least annually. This evaluation of proved and proved plus probable oil and gas reserves is prepared in accordance with the reserve definitions contained in National Instrument 51-101 and the COGE Handbook.

The Company is also required to estimate the recoverable amount of exploration and evaluation assets, which consists of undeveloped lands, exploratory drilling assets and bitumen evaluation assets, for impairment testing. The recoverable amount is based on relevant industry sales value data.

ii) Marketable securities

Rubellite Share Purchase Warrants are recorded at fair value using the Black Scholes option pricing model. In assessing the fair value of the warrants, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, and risk-free rate.

iii) Provisions for decommissioning obligations

Decommissioning, abandonment, and site reclamation expenditures for production facilities, wells, and pipelines are expected to be incurred by the Company over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation, liability specific discount rates and related cash flows. The provision represents management's best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

iv) Derivative financial instruments

Derivatives are measured at fair value on each reporting date. Fair value is the price that would be received or paid to exit the position as of the measurement date. The Company uses estimated external forecasted market commodity and foreign exchange price curves available at period end and the contracted volumes over the contracted term to determine the fair value of each contract. Changes in market pricing between period end and settlement of the derivative contracts could have a material impact on financial results related to the derivatives.

v) Other liability

The other liability is measured at fair value on each reporting date. The fair value of the other liability is estimated by discounting future cash payments based on Perpetual's annual average realized oil and natural gas prices exceeding certain thresholds. Changes in market pricing between period end and settlement could have a material impact on financial results related to the other liability.

vi) Royalty obligations

The retained East Edson royalty obligation and the gas over bitumen royalty financing are measured at fair value on each reporting date. The fair value is estimated by discounting future cash payments based on the forecasted natural gas and NGL commodity prices multiplied by the remaining royalty obligation volumes. Changes in market pricing between period end and settlement could have a material impact on financial results related to the royalty obligations.

vii) Share-based payments

Share options, deferred share options, and long-term incentive awards issued by the Company are recorded at fair value using the Black Scholes option pricing model. In assessing the fair value of share options and deferred share options, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these annual consolidated financial statements and have been applied consistently by the Company and its subsidiaries.

a) Basis of consolidation

i) Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that are currently exercisable are considered. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases

ii) Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued, and liabilities incurred or assumed at the date of acquisition of control. Identifiable assets acquired, and liabilities assumed in a business combination are measured at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets acquired and liabilities assumed is recorded as goodwill. If the cost of acquisition is less than the recognized amount of the net assets acquired, the difference is recognized as a bargain purchase gain in net income (loss).

iii) Jointly owned assets

Many of the Company's oil and gas activities involve jointly owned assets which are not conducted through a separate entity. The consolidated financial statements include the Company's proportionate share of these jointly owned assets, liabilities, revenues and expenses.

iv) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

b) Financial instrument

Financial instruments comprise cash, accounts receivable, marketable securities, deposits, fair value of derivative assets and liabilities, accounts payable and accrued liabilities, revolving bank debt, Term Loan, other liability, royalty obligations, and senior notes. These financial instruments are recognized initially at fair value, net of any directly attributable transaction costs.

i) Classification and measurement of financial assets

A financial asset is measured at amortized cost if it meets both of the following conditions and is not designated at fair value through profit or loss ("FVTPL"):

- it is held within a business model whose objective is to hold assets to collect contractual cash flows; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

A debt investment is measured at fair value through other comprehensive income ("FVOCI") if it meets both of the following conditions and is not designated at FVTPL:

- it is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

On initial recognition of an equity investment that is not held for trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in other comprehensive income ("OCI"). This election is made on an investment-by-investment basis.

All financial assets not classified as measured at amortized cost or FVOCI as described above are measured at FVTPL. On initial recognition, the Company may irrevocably designate a financial asset that otherwise meets the requirements to be measured at amortized cost or at FVOCI at FVTPL if doing so eliminates or significantly reduces an accounting mismatch that would otherwise arise.

A financial asset (unless it is a trade receivable without a significant financing component that is initially measured at the transaction price) is initially measured at fair value plus, for an item not at FVTPL, transaction costs that are directly attributable to its acquisition.

The following accounting policies apply to the subsequent measurement of financial assets:

a) Financial assets at FVTPL

These assets are subsequently measured at fair value. Net gains and losses, including any interest or dividend income, are recognized in profit or loss.

b) Financial assets at amortized cost

These assets are subsequently measured at amortized cost using the effective interest method. The amortized cost is reduced by impairment losses. Interest income, foreign exchange gains and losses and impairment are recognized in profit or loss. Any gain or loss on derecognition is recognized in profit or loss.

ii) Classification and measurement of financial liabilities

Financial liabilities are classified and measured at amortized cost or FVTPL. A financial liability is classified at FVTPL if it is a derivative or it is designated as such on initial recognition. Financial liabilities at FVTPL are measured at fair value and net gains and losses, including any interest expense, are recognized in profit or loss. Other financial liabilities are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in profit or loss. Any gain or loss on derecognition is also recognized in profit or loss.

The Company has classified cash, accounts receivable, deposits, accounts payable and accrued liabilities, revolving bank debt, Term Loan and senior notes as amortized cost. The marketable securities, other liability, and royalty obligations have been classified as FVTPL.

iii) Derivative assets and liabilities

The Company has entered into certain financial derivative contracts to manage the exposure to market risks from fluctuations in commodity prices and currency rates. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all commodity and currency contracts to be economic hedges. As a result, all financial derivative contracts are designated as FVTPL and recorded as derivatives on the statement of financial position at fair value. Changes in the fair value of the commodity price and currency rate derivatives are recognized in net income (loss).

The Company has accounted for its forward physical delivery fixed-price sales contracts as derivative financial instruments. Accordingly, such forward physical delivery fixed-price sales contracts are designated as FVTPL and recorded as derivatives on the statement of financial position at fair value.

Transaction costs on derivatives are recognized in net income (loss) when incurred.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at FVTPL. Changes in the fair value of separable embedded derivatives are recognized immediately in net income (loss).

iv) Share capital and warrants

Incremental costs directly attributable to the issue of common shares, warrants and share options are recognized as a deduction from equity, net of any tax effects.

c) Inventory

Product inventory consists of the Company's unsold crude oil and is valued at the lower of cost or net realizable value. The cost of crude oil is determined on a first-in first-out basis. Costs include the direct and indirect expenditures incurred in the normal course of business to bring the product to its existing condition and location. Net realizable value is the estimated selling price less applicable expenditures required to sell the product. If the carrying value exceeds the net realizable value, a write down is recognized. Write-downs may be reversed in a subsequent period if the inventory is still on hand and the circumstances which caused the write-down no longer exist.

d) Property, plant and equipment (PP&E)

i) Development and Production costs

Items of property, plant and equipment, which include development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The initial cost of property, plant and equipment includes the purchase price or construction costs, costs that are directly attributable to bringing the asset into commercial operations, the initial estimate of decommissioning costs, and borrowing costs for qualifying assets.

Significant parts of an item of property, plant and equipment, including development and production assets, that have different useful lives from the life of the area or facility in general, are accounted for as separate items.

Gains and losses on disposition of an item of property, plant and equipment, including development and production assets, are determined by comparing the proceeds from disposition with the carrying amount of property, plant and equipment and are recognized in net income (loss). Proceeds may include cash, or other non-cash consideration such as retained drilling rights which are fair valued at the time of disposition. The carrying amount of any replaced or disposed item of property, plant and equipment is derecognized.

ii) Subsequent costs

Costs incurred after the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as property, plant and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized property, plant and equipment generally represent costs incurred in developing proved and/or probable oil and gas reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. All other expenditures including the costs of the day-to-day servicing of property, plant and equipment are recognized as production and operating expense in net income (loss) as incurred.

iii) Depletion and depreciation

The Company depletes its net carrying value of development and production assets using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable oil and gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. The forecasted future development cost estimates are reviewed by independent third-party reserve evaluators at least annually.

Costs associated with office furniture, information technology, and leasehold improvements are carried at cost and are depreciated on a straight-line basis over a period ranging from one to three years.

Depreciation methods, useful lives and residual values are reviewed at each period end date for all classes of property, plant, and equipment.

e) Exploration and evaluation expenditures (E&E)

Pre-license costs, geological and geophysical costs, and lease rentals of undeveloped properties are recognized in net income (loss) as incurred.

E&E costs, consisting of the costs of acquiring oil and gas licenses, are capitalized initially as E&E assets according to the nature of the assets acquired. Costs associated with drilling exploratory wells in an undeveloped area are capitalized as E&E costs. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability. When technical feasibility and commercial viability are determined, the relevant expenditure is transferred to property, plant and equipment as development and production assets, after impairment is assessed and any applicable impairment loss is recognized in net income (loss).

The Company's E&E assets consist of undeveloped lands, exploratory drilling assets, and bitumen evaluation assets. Gains and losses on disposition of E&E assets are determined by comparing the proceeds from disposition with the carrying amount and are recognized in net income (loss).

f) Right-of-use assets

The Company recognizes right-of-use assets and lease liabilities at the lease commencement date. The assets are measured at the lease liability initially recognized, which comprise the present value of the future lease payments 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 right-of-use assets are depreciated to the earlier of the end of the useful life of the asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. The Company presents right-of-use assets as its own line item on the consolidated statements of financial position. In determining the lease term, management considers the non-cancellable period along with all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. In addition, the right-of-use assets are periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liabilities. The depreciation term of the right-of-use assets is between two and five years.

g) Lease Liabilities

The lease liabilities are initially measured at the present value of the future lease payments, discounted using the interest 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, which is determined based on judgments about the economic environment in which the Company operates and theoretical analyses about the security provided by the underlying leased asset, the amount of funds required to be borrowed in order to meet the future lease payments associated with the leased asset, and the term for which these funds would be borrowed.

The lease liabilities are measured at amortized cost using the effective interest rate method. They are remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liabilities are remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use assets, or is recorded in profit or loss if the carrying amount of the right-of-use assets has been reduced to zero. Lease payments are applied against the lease liabilities, with a portion allocated as cash finance expense using the effective interest rate method. The Company presents lease liabilities as their own line item on the consolidated statements of financial position.

h) Assets held for sale

Non-current assets, or disposal groups consisting of assets and liabilities ("disposal groups"), are classified as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use. Assets and liabilities qualifying as held for sale must be available for immediate sale in their present condition subject to normal terms and conditions, and their sale must be highly probable.

Non-current assets, or disposal groups, are measured at the lower of the carrying amount and FVLCD, with impairments recognized in net income (loss). Non-current assets or disposal groups held for sale are presented in current assets and liabilities within the statement of financial position. Assets held for sale are not subject to depletion and depreciation.

i) Impairment

i) Financial assets

The Company has elected to measure loss allowances for trade receivables and contract assets at an amount equal to lifetime expected credit losses ("ECLs"). The maximum period considered when estimating ECLs is the maximum contractual period over which the Company is exposed to credit risk.

ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the financial asset.

Loss allowances for financial assets are deducted from the gross carrying amount of the assets. Impairment losses on financial assets are presented under "other expenses" in the consolidated statements of income (loss) and comprehensive income (loss).

ii) Non-financial assets

The carrying amounts of the Company's property, plant and equipment, which includes development and production assets, are reviewed at each period end date to determine whether there are any internal or external indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together at a CGU level. The estimated recoverable amount of an asset or a CGU is determined based on the higher of its FVLCD and its VIU. FVLCD is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCD of development and production assets is generally determined as the net present value of estimated future cash flows expected to arise from the continued use of the CGU and its eventual disposition, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. In determining VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. VIU is generally the future cash flows expected to be derived from production of proved and probable oil and gas reserves estimated by the Company's independent third-party reserve evaluators.

An impairment is recognized if the carrying amount of a CGU exceeds the estimated recoverable amount for that CGU. The Company determines the estimated recoverable amount by using the greater of FVLCD and the VIU. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amount of assets in the unit (group of units) on a pro rata basis. Impairment losses are recognized in net income or loss.

E&E assets are assessed for impairment at the time that any triggering facts and circumstances suggest that the carrying amount exceeds the estimated recoverable amount as well as upon their eventual reclassification to development and production assets in property, plant and equipment. If a test is required as a result of triggering facts and circumstances, the Company considers whether the combined estimated recoverable amount of the CGUs and E&E assets at the total company level is sufficient to cover the combined carrying value of the CGUs and E&E assets.

In respect of other assets, impairment losses recognized in prior years are assessed at each period end date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

j) Share-based payments

Fixed equity awards granted under the equity-settled share-based payment plans and agreements are measured at grant-date fair value. Fair values are determined by means of an option pricing model using the exercise price of the equity instrument granted, the share price at the grant date, the expected life of the grant based on the vesting date and expiry date, estimates of share price volatility, and interest rates over the expected contractual life of the equity award. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest.

The costs of the equity-settled share-based payments are recognized within general and administrative expense, production and operating expense, or property, plant and equipment to the extent they are directly attributable, with a corresponding increase in contributed surplus over the vesting period. Upon exercise or settlement of an equity-based instrument, consideration received, and associated amounts previously recorded in contributed surplus are recorded to share capital.

Certain awards granted under the performance share rights plan may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Company's Board of Directors. Fixed value, equity-settled awards are accounted for as cash-settled share-based payment transactions and are expensed into profit and loss over the unit vesting period with an associated accumulation in accounts payable and accrued liabilities, as a variable number of equity units will be required to settle the liability.

k) Shares held in trust

The Company has share-based payment plans whereby employees may be entitled to receive shares of the Company purchased on the open market by a trustee controlled by the Company. Shares acquired and held by the trustee for the benefit of employees that have not yet been issued to employees, are a separate category of equity that are presented net of common shares outstanding in share capital on the consolidated statements of financial position (note 17(b)). The balance of shares held in trust represents the cumulative cost of shares held by the trustee. Upon the issuance of shares to the employee, the amount attributable to an employee is deducted from the balance of shares held in trust and removed from contributed surplus.

l) Provisions

Provisions are recognized when the Company has a current legal or constructive obligation as a result of a past event, which can be reliably estimated, and will require the outflow of economic resources to settle the obligation. A non-current provision is determined using the estimated future cash flows discounted at a rate that reflects current market conditions and obligation specific risks.

i) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. A provision is recorded for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's estimate of the extent and timing of expenditures required to settle the obligation at the statement of financial position date, using a risk-free interest rate not adjusted for credit risk. Subsequent to the initial measurement, the obligation is adjusted at the end of each reporting period to reflect the passage of time, changes in the timing and estimate of future cash flows underlying the obligation, and changes in the risk-free rate. The accretion of the provision due to the passage of time is recognized in net income (loss) whereas changes in the provision arising from changes in estimated cash flows or changes in the risk-free rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

m) Revenue

Revenue from the sale of heavy crude oil, conventional natural gas and NGL is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the buyer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipelines or other transportation method agreed upon.

Revenues from processing activities are recognized over time as processing occurs and are generally billed monthly.

Royalty income is recognized monthly as it accrues in accordance with the terms of the royalty agreements.

When allocating the transaction price realized in contracts with multiple performance obligations, management is required to make estimates of the prices at which the Company would sell the product separately to customers. The Company does not currently have any contracts with multiple performance obligations.

If the consideration promised in a contract includes a variable amount, the Company estimates the amount of consideration to which it will be entitled in exchange for transferring the promised goods or services to a customer. Royalty obligations (note 13) are considered to be variable consideration that will be remeasured at fair value at each reporting date.

The Company's entitlement to gas over bitumen royalty adjustments under the Natural Gas Royalty Regulation (2004) with respect to foregone production (deemed production) from natural gas wells shut-in for the benefit of bitumen producers in the Athabasca oil sands area, is recognized as gas over bitumen royalty credit revenue in the period that deemed production occurs, to the extent that the revenue is expected to be recovered through gas Crown royalties otherwise payable. The final payment related to the gas over bitumen royalty financing was made on July 25, 2021.

n) Income tax

Income tax expense comprises current and deferred components. Income tax expense is recognized in net income (loss) except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

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

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the period end date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be sufficient to utilize the underlying deductible temporary differences and unused tax losses associated with the deferred tax asset. The determination of probable future taxable profits involves significant estimates, including proved and probable oil and gas reserves. Deferred tax assets are reviewed at each period end date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

o) Income (loss) per share amounts

Basic income or loss per share is calculated by dividing the net income (loss) by the weighted average number of common shares outstanding during the period. For the dilutive net income per share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income.

Diluted income per share is calculated giving effect to the potential dilution that would occur if outstanding warrants, share options, restricted rights, performance share rights, or deferred compensation awards were exercised or converted into common shares. The weighted average number of diluted shares is calculated in accordance with the treasury stock method for warrants, share options, restricted rights, performance share rights and deferred compensation awards. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase common shares at the average market price.

p) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received, and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as an expense reduction in the period in which the costs are incurred. Government grants related to income are recorded as other income in the period in which eligible expenses were incurred or when the services have been performed. During the year ended December 31, 2021, the Company received government grants through the Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") of $0.9 million. For the year ended December 31, 2021, the grants were recognized as a reduction to general and administrative and production and operating expenses of $0.8 million and $0.1 million, respectively.

The Company also received government grant funding pursuant to Alberta's Site Rehabilitation Program ("SRP") with respect to approved abandonment and reclamation expenditures incurred by the Company. SRP funding of $0.3 million was received in 2022 (2021 - $0.7 million) and has been reported as other income (note 15).

q) Changing regulation

Regulations and government programs regarding emissions and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the IASB has issued an IFRS Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards and others that may be developed over time has not yet been quantified.

4. MARKETABLE SECURITIES

		Amount *($thousands)*
December 31, 2020	$	—
Rubellite shares and warrants received (note 4)[1]		9
Warrants exercised (note 17(d))		118
AIMCo Bonus Shares received (note 10)[2]		1,361
AIMCo Bonus Shares delivered (note 10)[2]		(1,361)
Rubellite Share Purchase Warrants received		2,000
Change in fair value of marketable securities		282
December 31, 2021	$	2,409
Purchase		39
Change in fair value of marketable securities		(634)
December 31, 2022	**$**	**1,814**

(1) On September 3, 2021, a Plan of Arrangement was completed involving Perpetual, the shareholders of Perpetual, and Rubellite Energy Inc. ("Rubellite") (the "Arrangement"). Under the terms of the Arrangement, for every 46 common shares of Perpetual held, shareholders received 1 common share of Rubellite and 12 warrants to purchase Rubellite common shares ("Rubellite Warrants"). Each Rubellite Warrant entitled the holder to subscribe for one Rubellite common share at a price of $2.00 per share until October 4, 2021. Through it's employee trust, Perpetual received 4,500 Rubellite common shares and 54,000 Rubellite Warrants as part of the Arrangement.

(2) Upon completion of the Arrangement, Perpetual executed its agreement with its Term Loan lender for the settlement of principal and all interest owing on the Term Loan ("Second Line Loan Settlement"). As part of the Second Lien Loan Settlement, Perpetual delivered 680,485 Rubellite shares (the "AIMCo Bonus Shares) to the second lien lender. The AIMCo Bonus Shares were valued at $1.4 million.

As at December 31, 2022 the Company holds 58,500 Rubellite shares on behalf of its employees valued at $0.1 million using the Rubellite common share price of $1.85 per share.

Under the terms of the Arrangement, Perpetual also received 4.0 million Rubellite Share Purchase Warrants, with an exercise price of $3.00 per share, that were initially valued at $2.0 million when received and revalued to $1.4 million as at December 31, 2022. The Company used the Black Scholes pricing model to calculate the estimated fair value of the Rubellite Share Purchase Warrants.

The following assumptions were used to arrive at the estimate of fair value of the Rubellite Share Purchase Warrants at the initial grant date upon completion of the Arrangement and as at period end:

	December 31, 2022	**Grant Date**
Dividend Yield (%)	**—**	—
Expected volatility (%)	**40%**	40%
Risk-free interest rate (%)	**3.28%**	1.20%
Contractual life (years)	**3.7**	5.0
Share price	**$1.85**	$2.00
Exercise price	**$3.00**	$3.00
Fair value	**$0.34**	$0.50

5. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

		Development and Production Assets		Corporate Assets		Total
Cost						
December 31, 2020	$	564,959	$	7,652	$	572,611
Additions		19,060		2		19,062
Acquisitions		1,325		—		1,325
Change in decommissioning obligations related to PP&E (note 15)		2,689		—		2,689
Transfers from exploration and evaluation (note 6)		2,943		—		2,943
Dispositions (a)		(16,442)		—		(16,442)
December 31, 2021	$	574,534	$	7,654	$	582,188
Additions		31,772		137		31,909
Change in decommissioning obligations related to PP&E (note 15)		(4,655)		—		(4,655)
Transfers from exploration and evaluation (note 6)		161		—		161
December 31, 2022	**$**	**601,812**	**$**	**7,791**	**$**	**609,603**
Accumulated depletion and depreciation						
December 31, 2020	$	(441,059)	$	(7,567)	$	(448,626)
Depletion and depreciation		(13,500)		(67)		(13,567)
Dispositions (a)		3,025		—		3,025
Impairment reversal (b)		30,600		—		30,600
December 31, 2021	$	(420,934)	$	(7,634)	$	(428,568)
Depletion and depreciation(1)		(17,781)		(10)		(17,791)
Impairment reversal (b)		7,400		—		7,400
December 31, 2022	**$**	**(431,315)**	**$**	**(7,644)**	**$**	**(438,959)**
Carrying amount						
December 31, 2021	$	153,600	$	20		153,620
December 31, 2022	**$**	**170,497**	**$**	**147**		**170,644**

(1) During the year ended December 31, 2022, depletion and depreciation expense includes $0.3 million which has been capitalized to inventory in accordance with the Company's inventory policy (December 31, 2021 - nil).

For the year ended December 31, 2022, $2.2 million (December 31, 2021 – $0.4 million) of direct general and administrative expenses were capitalized. Future development costs for the period ended December 31, 2022 of $104.6 million (December 31, 2021 – $75.3 million) were included in the depletion calculation. Depletion was $17.8 million (December 31, 2021 - $13.5 million) on development and production assets for the year ended December 31, 2022.

a) Clearwater Assets Disposition

On September 3, 2021, the Arrangement was completed involving Perpetual, the shareholders of Perpetual, and Rubellite. The Arrangement resulted in the disposition of all of Perpetual's Clearwater lands, wells, roads and facilities in northeast Alberta (the "Clearwater Assets"), working capital and associated cash, and decommissioning obligations to Rubellite was accounted for as being effective for consideration of $65.5 million.

Consideration included $53.6 million in promissory notes, paid in cash on October 5, 2021, and the assumption of $5.8 million of promissory notes due to 1974918 Alberta Ltd. (a company controlled by the Company's CEO ("CEO") ("197Co"), the issuance of 680,485 Rubellite common shares valued at $1.4 million ("AIMCo Bonus Shares"), the return of 8.2 million Perpetual common shares exchanged in the Arrangement valued at $2.8 million and issuance of warrants to purchase 4.0 million Rubellite common shares at a price of $3.00 per share for a period of five years, valued at $2.0 million.

The consideration received, and calculation of the gain recorded on disposition is summarized below:

($ thousands)		
Proceeds from disposition (i)	**$**	**65,514**
Transaction costs and closing adjustments (ii)		**(583)**
Carrying amount of assets disposed (iii)		**(19,085)**
Carrying amount of net working capital disposed, including cash (iv)		**823**
Carrying amount of decommissioning obligations disposed (v)		**853**
Gain on disposition	**$**	**47,522**

i) Total consideration — $65.5 million of consideration as outlined below:

($ thousands)		
Promissory note issued by Rubellite to Perpetual[1]	$	53,600
PEI-197Co note assumed by Rubellite[2]		5,773
AIMCo Bonus Shares[3]		1,361
Perpetual common shares[4]		2,780
Rubellite Share Purchase Warrants[5]		2,000
Total consideration received		**$65,514**

(1) Demand promissory note, secured by the Clearwater Assets, and settled on October 5, 2021.
(2) On July 15, 2021, Perpetual exercised an option to acquire certain E&E lands located at Figure Lake in exchange for a demand promissory note secured by the Figure Lake lands in the amount of $5.8 million owing to 197Co (note 6). The acquired Figure Lake lands comprised part of the Clearwater Assets sold to Rubellite. The secured promissory note obligation owing to 197Co was assigned by Perpetual to Rubellite as part of the total consideration.
(3) Rubellite shares issued to Perpetual on September 3, 2021 valued at $1.4 million.
(4) Rubellite returned to Perpetual 8.2 million Perpetual common shares valued at $2.8 million. Pursuant to the Plan of Arrangement, Perpetual shareholders exchanged 8.2 million Perpetual common shares with Rubellite for Rubellite common shares and warrants. The Perpetual shares received were subsequently cancelled.
(5) Represents the estimated value of 4.0 million Rubellite Share Purchase Warrants at $3.00 per share exercise price (note 4) valued at $2.0 million.

ii)	Transaction costs and closing adjustments	$0.6 million of transaction costs and closing adjustments.
iii)	Carrying amount of assets disposed	$19.1 million of assets including development and production assets ($16.1 million of costs less $2.8 million of accumulated depletion) and exploration and evaluation assets ($5.8 million).
iv)	Carrying amount of net working capital disposed	$0.8 million of net working capital including cash ($4.1 million), accounts receivable ($0.7 million), and accounts payable ($5.6 million).
v)	Carrying amount of decommissioning obligations disposed	$0.9 million of decommissioning obligations associated with development and production assets disposed.

b) Cash-generating units and impairment reversals

There were no indicators of impairment for the Company’s cash generating units ("CGUs") as at December 31, 2022 and therefore, an impairment test was not performed.

The Company identified an indicator of impairment reversal at March 31, 2022 for the Eastern Alberta CGU and performed an impairment reversal test to estimate the recoverable amount of the CGU. It was determined the recoverable amount of the Eastern Alberta CGU exceeded the CGU’s carrying value, resulting in all previous Eastern Alberta CGU impairment, net of depletion, of $7.4 million being reversed. No historical impairments remain for the Eastern Alberta CGU.

At March 31, 2022, indicators of impairment reversal for the Eastern Alberta CGU were primarily a result of increased forecasted benchmark commodity prices which positively impacted operating cash flows. The estimated recoverable amount of the Eastern Alberta CGU was determined using the value-in-use methodology, based on the estimates of proved and probable oil and gas reserves and the related cash flows at March 31, 2022, as updated by internal reserve evaluators, along with forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 10% and 20% to consider risks specific to the Eastern Alberta CGU. For purposes of the March 31, 2022 impairment test, the Company's internal reserve evaluators updated the significant assumptions from the independent third party reserve evaluators estimate of proved and probable oil and gas reserves as at December 31, 2021.

Forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators were used in the VIU calculation as at March 31, 2022:

Year	West Texas Intermediate ("WTI") Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*	NYMEX Gas *(Cdn$/MMBtu)*
2022	94.53	1.25	95.13	5.13	5.48
2023	84.15	1.25	77.65	4.28	4.44
2024	77.51	1.25	70.24	3.69	3.75
2025	71.63	1.25	64.45	3.45	3.56
2026	73.06	1.25	65.74	3.52	3.63
2027	74.53	1.25	67.06	3.59	3.70
2028	76.02	1.25	68.40	3.66	3.77
2029	77.54	1.25	69.77	3.73	3.85
2030	79.09	1.25	71.16	3.81	3.93
2031	80.67	1.25	72.58	3.88	4.00
2032	82.28	1.25	74.04	3.96	4.08
2033	83.93	1.25	75.52	4.04	4.17
2034	85.61	1.25	77.03	4.12	4.25
2035	87.32	1.25	78.57	4.20	4.33
2036(1)	89.06	1.25	80.14	4.29	4.42

(1) Forecasted oil and gas commodity prices escalate 2.0% per year thereafter.

As at March 31, 2022, if discount rates used in the calculation of impairment reversal changed by 1% with all other variables held constant, the impairment reversal would be unchanged. As at March 31, 2022, if commodity price estimates changed by 5% with all other variables held constant, the impairment reversal would be unchanged.

During the year ended December 31, 2021, the Company reversed $30.6 million of historical impairments, net of depletion.

The Company identified an indicator of impairment reversal at June 30, 2021 for the West Central and Eastern Alberta cash generating units and additionally at December 31, 2021 for the Eastern Alberta CGU and performed impairment reversal tests to estimate the recoverable amount of each CGU. It was determined the recoverable amount of the West Central and Eastern Alberta CGUs exceeded each CGU's carrying value, resulting in all previous West Central impairment, net of depletion, of $22.6 million and Eastern Alberta impairment of $8.0 million, respectively, being reversed. No historical impairments remain for the West Central CGU.

At December 31, 2021, indicators of impairment reversal for the Eastern Alberta CGU included the recovery in global oil and gas commodity prices, changing development plans, positive proved and probable oil and gas reserve revisions, and increasing economic stability and certainty in the oil and gas industry, all of which positively impact operating cash flows. There were no internal or external indicators of impairment for the West Central CGU as at December 31, 2021. The estimated recoverable amount of the Eastern Alberta CGU was determined using the value-in-use methodology, based on the estimates of proved and probable oil and gas reserves and the related cash flows as evaluated by the Company's independent third party reserve evaluators at December 31, 2021, along with forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 10% and 20% to consider risks specific to the Eastern Alberta CGU.

At December 31, 2021, the Company determined that the estimated recoverable amount of the Eastern Alberta CGU exceeded the carrying amount of $42.2 million. Accordingly, an impairment reversal of $0.5 million was included in net income.

Forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators were used in the VIU calculation as at December 31, 2021:

Year	West Texas Intermediate ("WTI") Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*	NYMEX Gas *(Cdn$/MMBtu)*
2022	72.83	0.797	66.45	3.56	4.83
2023	68.78	0.797	61.90	3.21	4.32
2024	66.76	0.797	59.45	3.05	3.98
2025	68.09	0.797	60.64	3.11	4.06
2026	69.45	0.797	61.87	3.17	4.15
2027	70.84	0.797	63.11	3.23	4.23
2028	72.26	0.797	64.37	3.30	4.31
2029	73.70	0.797	65.67	3.36	4.40
2030	75.18	0.797	66.68	3.43	4.49
2031	76.68	0.797	68.02	3.50	4.58
2032	78.21	0.797	69.38	3.57	4.67
2033	79.78	0.797	70.77	3.64	4.76
2034	81.37	0.797	72.18	3.71	4.86
2035	83.00	0.797	73.63	3.79	4.95
2036(1)	84.66	0.797	75.10	3.86	5.05

(1) Forecasted oil and gas commodity prices escalate 2.0% per year thereafter.

As at December 31, 2021, if discount rates used in the calculation of impairment reversal changed by 1% with all other variables held constant, the impairment reversal would change by approximately $1.5 million. As at December 31, 2021, if commodity price estimates changed by 5% with all other variables held constant, the impairment reversal would change by approximately $5.8 million.

At June 30, 2021, indicators of impairment reversal for the West Central and Eastern Alberta CGUs related to the significant recovery in global oil and natural gas prices, coupled with the increasing economic stability and certainty in the oil and natural gas industry which positively impacts operating cash flows. The estimated recoverable amounts of the CGUs were determined using VIU based on the estimates of proved and probable oil and gas reserves and the related cash flows as evaluated or reviewed by the Company's independent third party reserves evaluators and updated by internal reserve evaluators, along with forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators as at July 1, 2021, and an estimate of market discount rates between 12% and 22% to consider risks specific to the CGUs.

The Company determined that the estimated recoverable amounts of the West Central CGU and Eastern Alberta CGU exceeded their carrying amounts of $89.6 million and $28.6 million, respectively. Accordingly, an impairment reversal of $30.1 million was included in net income in the second quarter of 2021.

Forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators were used in the VIU calculations as at June 30, 2021:

Year	WTI Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*	NYMEX Gas *(Cdn$/MMBtu)*
2021	66.59	0.80	61.66	3.18	4.16
2022	67.20	0.80	61.13	3.13	3.98
2023	63.95	0.80	55.88	2.72	3.65
2024	63.23	0.80	54.95	2.71	3.70
2025	64.50	0.80	56.06	2.76	3.78
2026	65.79	0.80	57.19	2.82	3.85
2027	67.10	0.80	58.34	2.88	3.93
2028	68.44	0.80	59.51	2.94	4.01
2029	69.81	0.80	60.71	2.99	4.09
2030	71.21	0.80	61.92	3.05	4.17
2031	72.63	0.80	63.16	3.12	4.26
2032	74.09	0.80	64.43	3.18	4.34
2033	75.57	0.80	65.71	3.24	4.43
2034	77.08	0.80	67.03	3.31	4.52
2035(1)	78.62	0.80	68.37	3.37	4.61

(1) Commodity price estimates escalate 2.0% per year thereafter.

6. EXPLORATION AND EVALUATION ("E&E")

	December 31, 2022	December 31, 2021
Balance, beginning of year	**$ 7,329**	$ 10,272
Acquisitions	**—**	5,773
Dispositions	**—**	(5,773)
Transfers to property, plant and equipment (note 5)	**(161)**	(2,943)
Balance, end of year	**$ 7,168**	$ 7,329

During the year ended December 31, 2022, $0.1 million (2021 - $0.1 million) in costs were charged directly to E&E expense in net income (loss).

On July 15, 2021, Perpetual exercised an option to acquire lands located at Figure Lake in exchange for a demand promissory note secured by the Figure Lake lands in the amount of $5.8 million owing to 197Co. The acquired Figure Lake lands comprised part of the Clearwater Assets sold to Rubellite. The secured promissory note obligation owing to 197Co was assigned by Perpetual to Rubellite as part of the disposition of the Clearwater Assets.

Impairment of E&E assets

E&E assets are tested for impairment both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to development and production assets in PP&E.

At December 31, 2022 and 2021, the Company conducted an assessment of indicators of impairment and impairment reversal for the Company's E&E assets. There were no triggers identified and therefore, an impairment test was not performed. The Company transferred undeveloped land to PP&E in 2022 at a value of $0.2 million (2021 - $2.9 million), which was equal to the book value in E&E.

7. RIGHT-OF-USE ASSETS

The Company leases several assets including office space, vehicles, and other leases. Information about leases for which the Company is a lessee is presented below:

	Head office	**Vehicles**	**Other leases**	**Total**
Cost				
January 1, 2021	$ 1,591	$ 389	$ 247	$ 2,227
Additions	—	221	—	221
December 31, 2021	$ 1,591	$ 610	$ 247	$ 2,448
Additions	—	181	—	181
December 31, 2022	**$ 1,591**	**$ 791**	**$ 247**	**$ 2,629**
Accumulated depreciation				
January 1, 2021	$ (497)	$ (215)	$ (143)	$ (855)
Depreciation	(258)	(134)	(61)	(453)
December 31, 2021	$ (755)	$ (349)	$ (204)	$ (1,308)
Depreciation	(258)	(170)	(29)	(457)
December 31, 2022	**$ (1,013)**	**$ (519)**	**$ (233)**	**$ (1,765)**
Carrying amount				
December 31, 2021	$ 836	$ 261	$ 43	$ 1,140
December 31, 2022	**$ 578**	**$ 272**	**$ 14**	**$ 864**

8. CONTINGENCIES

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy (the "Trustee") of Sequoia Resources Corp. ("Sequoia"), with the Alberta Court of Queen's Bench (the "Court"), against Perpetual (the "Sequoia Litigation"). The claim relates to a six-year-old transaction when, on October 1, 2016, Perpetual closed the disposition of shallow conventional natural gas assets in Eastern Alberta to an arm's length third party at fair market value after an extensive and lengthy marketing, due diligence, and negotiation process (the "Sequoia Disposition"). This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and applications to the Court to dismiss all claims has been made on the basis that there is no merit to any of them.

On January 13, 2020, a written decision related to the Application for Dismissal, dismissed and struck all claims against the Company's CEO and all but one of the claims filed against Perpetual. The Court did not find that the test for summary dismissal relating to whether the asset transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim could continue against Perpetual. The Trustee filed a notice of appeal with the Court of Appeal of Alberta, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal"). The First Appeal proceedings were heard on December 10, 2020. On January 25, 2021, the Court of Appeal of Alberta issued their judgement with respect to the First Appeal proceedings, dismissing the appeal filed by Perpetual and granting certain aspects of the appeals filed by the Trustee, thereby reinstating certain elements of the Sequoia Litigation for trial. On March 24, 2021, Perpetual applied for leave to appeal the First Appeal decision to the Supreme Court of Canada (the "SCC"). On July 8, 2021, the SCC dismissed Perpetual's application.

On February 25, 2020, Perpetual filed a second application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the asset transaction nor caused to be insolvent by the asset transaction (the "Second Summary Dismissal Application"). In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the Second Summary Dismissal Application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1 and 2, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings. On January 14, 2021 the Court issued its decision, finding that the Trustee could not establish a necessary element of the BIA Claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded there is "no merit" to the BIA Claim and it summarily dismissed the balance of the Statement of Claim. The Trustee appealed this decision, and the Court of Appeal hearing took place on February 10, 2022, with the panel reserving judgement. On March 25, 2022, the Court of Appeal issued their judgement with respect to this matter and allowed PwC's appeal on the basis that the Court of Queen's Bench erred in law in its handling of the end-of-life obligations and that based on the record, it could not be concluded the error was without consequence, and that the Court of Queen's Bench also erred in agreeing to hear the Second Summary Dismissal Application. On this basis, the BIA Claim has been directed to trial.

The Trustee filed its Amended Statement of Claim with the Court on October 14, 2022. Perpetual filed its Statement of Defence to Amended Statement of Claim on December 12, 2022.

Management expects that the Company is more likely than not to be completely successful in defending against the Sequoia Litigation such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in these financial statements.

9. REVOLVING BANK DEBT

The Company has a first lien credit facility of $30.0 million (December 31, 2021 - $17 million) with an initial term to May 31, 2023. The initial term may be extended to May 31, 2024 subject to approval by the syndicate. If the facility is not extended all outstanding balances would be repayable on May 31, 2024. The next semi-annual borrowing base redetermination is scheduled to be completed on or before May 31, 2023.

As at December 31, 2022, $14.9 million was drawn (December 31, 2021 – $2.5 million) and $1.2 million of letters of credit had been issued (December 31, 2021 – $1.0 million) under the Company's credit facility. Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 3.0% and 5.5%. The effective interest rate on the Credit Facility at December 31, 2022 was 7.9%. For the year ended December 31, 2022 if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net income would be $0.1 million.

The Credit Facility is secured by general first lien security agreements covering all present and future property of the Company and its subsidiaries.

At December 31, 2022, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

10. TERM LOAN

			December 31, 2022		December 31, 2021	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	December 31, 2024	8.1%	**$ 2,671**	**$ 2,524**	$ 2,671	$ 2,469

During the third quarter of 2021, Perpetual executed an agreement with its Term Loan lender for the settlement of principal and all interest owing on the Term Loan. Perpetual substantively modified the previous Term Loan with Alberta Investment Management Corporation ("AIMCo") in exchange for the payment of approximately $38.5 million in cash, the delivery by Perpetual of the AIMCo Bonus Shares at a value of $1.4 million, the issuance of a new $2.7 million second lien Term Loan (the "New Term Loan"), and up to an aggregate $4.5 million in contingent payments over the three year period ended June 30, 2024 in the event that Perpetual's annual average realized oil and natural gas prices exceed certain thresholds (the "Second Lien Loan Settlement") (note 11). All amounts related to the Second Lien Loan Settlement were paid on October 5, 2021. The New Term Loan bears interest at 8.1% annually, which Perpetual may elect to pay-in-kind and will mature on December 31, 2024. Perpetual has the ability to repay the Term Loan at any time without any repayment penalty.

The Company and the Term Loan lender agreed to allow $1.8 million of interest due December 31, 2020 to be paid-in-kind and added to the outstanding principal amount of the loan and all other interest owing on the Term Loan to be settled as part of the Second Lien Loan Settlement. Non-cash paid-in-kind interest of $0.8 million was recorded in the third quarter of 2021, which increased the principal amount of the Term Loan owing upon settlement to $49.6 million. As a result of the Second Lien Loan Settlement, the carrying amount of $49.6 million was in excess of the consideration received of $42.8 million, resulting in a gain of $6.8 million being recognized (note 20).

The New Term Loan has a cross-default provision with the Credit Facility and contains substantially similar provisions and covenants as the Credit Facility (note 9). The Term Loan is secured by a general security agreement over all present and future property of the Company and its subsidiaries on a second priority basis, subordinate only to liens securing loans under the Credit Facility.

At December 31, 2022, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

11. OTHER LIABILITY

Pursuant to the terms of the Second Lien Loan Settlement, Perpetual committed to pay up to $4.5 million in potential contingent payments in the event that the Company's annual average realized crude oil and natural gas prices exceed certain thresholds in each of the annual periods ended December 31, 2023. The payment for 2021 was capped at $1.3 million; the payment for 2022 is capped at $1.3 million; and the payment for 2023 is capped at $1.9 million. For 2021, $0.2 million was earned and $0.1 million was paid on June 30, 2022, with the remaining $0.1 million to be paid on June 30, 2023. For 2022, $1.3 million was earned. This leaves a maximum remaining total obligation to be earned for 2023 of $2.0 million. At December 31, 2022, the Company estimated the maximum total remaining obligation to be $3.3 million, and after discounting the fair value of the contingent liability was recorded as $3.0 million. The change in fair value of this liability was recorded as a non-cash finance expense in the statements of income and comprehensive income.

The table below summarizes the change in fair value of the contingent payments:

	December 31, 2022	December 31, 2021
Balance, beginning of year	$ 1,387	$ —
Initial recognition	—	228
Cash payments	(63)	—
Change in fair value	1,678	1,159
Balance, end of year	$ 3,002	$ 1,387

	December 31, 2022	December 31, 2021
Current	$ 532	$ 63
Non-current	2,470	1,324
Total other liability	$ 3,002	$ 1,387

The Company has designated the other liability as financial liabilities which are measured at fair value through profit and loss, estimated by discounting potential contingent payments. For the year ended December 31, 2022, an unrealized loss of $1.7 million (2021 – $1.2 million) is included in non-cash finance expense related to the change in fair value of other liability (note 20).

At December 31, 2022, if forecasted natural gas commodity prices changed by $0.25 per GJ with all other variables held constant, the fair value of the total other liability and net income for the period would change by nil as the maximum remaining obligation has been met and this movement would not reduce the remaining obligation to less than it's maximum. If forecasted crude oil commodity prices changed by $5.00 per bbl with all other variables held constant, the fair value of the other liability and net income for the period would also change by nil for the same reason.

12. SENIOR NOTES

			December 31, 2022		December 31, 2021	
	Maturity date	Interest rate	Principal	Carrying Amount	Principal	Carrying amount
Senior notes	January 23, 2025	8.75%	$ 35,647	$ 34,527	$ 36,583	$ 34,189

On January 22, 2021, Perpetual announced the completion of a Court-approved plan of arrangement whereby the unsecured 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025. The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in cash, or in additional 2025 Senior Notes (a "PIK Interest Payment"). In 2021, the Company elected to pay the semi-annual interest payments by making PIK Interest Payments, increasing the principal amount to $36.6 million.

The Company satisfied the January 23, 2022 and the July 23, 2022 semi-annual interest payment of $1.6 million by making cash payments. Subsequent to December 31, 2022 the Company satisfied the January 23, 2023 semi-annual interest of $1.6 million by making a cash payment.

At December 31, 2022, the senior notes are recorded at the present value of future cash flows, net of $1.1 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.9%.

During the third quarter of 2022 the Company purchased and cancelled a portion of the 2025 Senior Notes balance with a carrying value of $0.9 million (2021 - nil) for gross proceeds of $0.8 million. A gain on extinguishment of $0.1 million (2021 - nil) is included in non-cash finance expense (note 20).

The senior notes are direct senior secured, third lien obligations of the Company. The Company may redeem the senior notes without any repayment penalty. The senior notes have a cross-default provision with the Company's Credit Facility. In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt, and stock repurchases.

At December 31, 2022, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Entities controlled by the Company's CEO hold $15.9 million of the 2025 Senior Notes outstanding. An entity that is associated with the Company's CEO holds an additional $10.3 million of the 2025 Senior Notes outstanding.

13. ROYALTY OBLIGATIONS

	Retained East Edson royalty obligation	Gas over bitumen royalty financing	Total
December 31, 2020	$ 5,714	$ 435	$ 6,149
Cash payments(1)	—	(558)	(558)
Non-cash payments in-kind	(4,995)	—	(4,995)
Change in fair value (note 20)	3,978	123	4,101
December 31, 2021	4,697	—	4,697
Cash payments(2)	**(6,953)**	**—**	**(6,953)**
Change in fair value (note 20)	**2,256**	**—**	**2,256**
December 31, 2022	**$ —**	**$ —**	**$ —**

(1) The final payment related to the gas over bitumen royalty financing was made on July 25, 2021.
(2) The retained East Edson royalty obligation ended on December 31, 2022.

The retained East Edson royalty obligation formed part of the net consideration received by Perpetual following the disposition transaction in 2020, whereby Perpetual agreed to retain the purchaser's 50% working interest in the existing gross overriding royalty obligation on the property, equivalent to 2.8 MMcf/d of natural gas and associated NGL production for the period April 1, 2020 to December 31, 2022. Prior to November 1, 2021, the retained East Edson royalty obligation was paid in-kind, and settled through non-cash delivery of contractual natural gas and NGL volumes to the royalty holder. As of November 1, 2021, the royalty obligation is settled through payment in cash.

The Company has designated the retained East Edson royalty obligation and the gas over bitumen royalty financing as financial liabilities which are measured at fair value through profit and loss, estimated by discounting future royalty obligations based on forecasted natural gas and NGL commodity prices multiplied by the royalty obligation volumes. For the year ended December 31, 2022, an unrealized loss of $2.3 million (2021 – unrealized loss of $4.1 million) is included in non-cash finance expense related to the change in fair value of the retained East Edson total royalty obligation (note 20).

14. LEASE LIABILITIES

	December 31, 2022	December 31, 2021
Balance, beginning of year	**$ 2,102**	$ 2,501
Additions	**181**	221
Interest on lease liabilities (note 20)	**116**	148
Payments	**(824)**	(768)
Total lease liabilities	**$ 1,575**	**$ 2,102**
Current	**$ 705**	$ 778
Non-current	**870**	1,324
Total lease liabilities	**$ 1,575**	**$ 2,102**

Lease terms are negotiated on an individual basis and contain a wide range of terms and conditions. Incremental borrowing rates used to measure the present value of the future lease payments at December 31, 2022 were between 4.3% and 6.6% (2021 – 4.3% and 6.6%).

15. DECOMMISSIONING OBLIGATIONS

The following significant assumptions were used to estimate decommissioning obligations:

	December 31, 2022	December 31, 2021
Obligations incurred, including acquisitions	$ 687	$ 965
Change in risk free interest rate	(5,325)	(1,309)
Change in estimates	(17)	3,033
Change in decommissioning obligations related to PP&E (note 5)	(4,655)	2,689
Obligations settled (cash)	(1,199)	(1,760)
Obligations settled[(1)] (non-cash)	(348)	(704)
Obligations disposed (note 5(a)(v))	—	(853)
Accretion (note 20)	727	531
Change in decommissioning obligations	(5,475)	(97)
Balance, beginning of year	32,927	33,024
Balance, end of year	$ 27,452	$ 32,927
Decommissioning obligations – current[(2)]	$ 1,688	$ 1,327
Decommissioning obligations – non-current	25,764	31,600
Total decommissioning obligations	$ 27,452	$ 32,927

(1) During the year ended December 31, 2022, obligations settled (non-cash) of $0.3 million (2021 – $0.7 million) respectively were funded by payments made directly to Perpetual's service providers from the Alberta Site Rehabilitation Program. These amounts have been recorded as other income.

(2) Current decommissioning liabilities relate to obligations that the Company reasonably expects to be settled within the next 12 months.

Decommissioning obligations are estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future periods. The Company's current decommissioning obligation exceeds the Alberta Energy Regulator's ("AER") required spend over the next twelve months.

The increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the condensed interim consolidated statements of income and comprehensive income. Decommissioning obligations are further adjusted at each period end date for changes in the risk-free interest rate, after considering additions and dispositions of PP&E. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future periods.

The following significant assumptions were used to estimate the Company's decommissioning obligations:

	December 31, 2022	December 31, 2021
Undiscounted obligations	$ 32,664	$ 32,254
Average risk-free rate	3.3%	1.7%
Inflation rate	2.1%	1.8%
Expected timing of settling obligations	1 to 25 years	1 to 25 years

16. CONTRACTUAL OBLIGATIONS

As at December 31, 2022, the Company's minimum contractual obligations and lease commitments over the next five years and thereafter, excluding estimated interest payments, are as follows:

	2023	2024	2025	2026	Total
Contractual obligations					
Accounts payable and accrued liabilities	18,962	–	–	–	18,962
Revolving bank debt	–	14,909	–	–	14,909
Term loan, principal amount	–	2,671	–	–	2,671
Senior notes, principal amount	–	–	35,647	–	35,647
Lease liabilities	705	680	190	–	1,575
Pipeline transportation commitments	1,924	1,659	1,293	319	5,195
Total	**21,591**	**19,919**	**37,130**	**319**	**78,959**

17. SHARE CAPITAL

	December 31, 2022		December 31, 2021	
	Shares ***(thousands)***	**Amount** ***($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**63,567**	**$ 94,809**	61,305	$ 97,333
Issued pursuant to share-based payment plans	**3,174**	**4,611**	1,828	243
Shares held in trust purchased (b)	**(1,334)**	**(1,307)**	(542)	(191)
Shares held in trust issued (b)	**537**	**502**	566	168
Treasury shares issued (c)	**—**	**—**	1,000	230
Shares held in trust sold pursuant to the Plan of Arrangement (d)	**—**	**—**	189	9
Shares held in trust split pursuant to the Plan of Arrangement (d)	**—**	**—**	(189)	—
Common share split (d)	**—**	**—**	8,158	—
Common share cancellation (d)	**—**	**—**	(8,158)	(2,779)
Common share odd-lot consolidation (e)	**—**	**—**	(590)	(204)
Balance, end of year	**65,944**	**$ 98,615**	63,567	$ 94,809

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Shares held in trust

The Company has compensation agreements in place with employees whereby they may be entitled to receive shares of the Company purchased on the open market by a trustee (note 18). Share capital is presented net of the number and cumulative purchase cost of shares held by the trustee that have not yet been issued to employees. As at December 31, 2022, 1.3 million shares were held in trust (December 31, 2021 – 0.5 million).

c) Treasury shares issued

During the first quarter of 2021, 1.0 million common shares were issued to an Officer of the Company for $0.2 million of cash consideration at a price of $0.23 per share, representing the volume weighted average trading price of the shares for the 5 day period immediately preceding the issuance.

d) Common share split and common share cancellation

As part of the Plan of Arrangement, 8.2 million Perpetual common shares were received by Rubellite from Perpetual shareholders in exchange for Rubellite common shares and warrants, and Perpetual split its shares by a ratio such that the number of Perpetual shares exchanged to Rubellite was equal to the number of shares split. On September 3, 2021, Perpetual received 8.2 million Perpetual common shares held by Rubellite as part of the consideration for the disposition of the Clearwater Assets and these shares were cancelled.

e) Common share odd-lot consolidation

Pursuant to steps in the Plan of Arrangement, Perpetual consolidated its common shares on the basis of 1,000 to 1 (the "Consolidation") and subsequently split the Common Shares on the same ratio. Shareholders who owned a number of common shares less than 1 subsequent to the consolidation and preceding the split (the "Consolidated Shareholders") were paid an amount in cash of $0.3419 per pre consolidated common share, being the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the 20-day period prior to the effective date. Based on the ratio, 590,000 Common Shares were cancelled as a result of the Consolidation and Perpetual paid an aggregate of $0.2 million to the Consolidated Shareholders.

f) Per share information

(thousands, except per share amounts)	**December 31, 2022**	December 31, 2021
Net income – basic and diluted	**$ 44,397**	$ 81,121
Weighted average shares		
Issued common shares	**65,213**	63,377
Effect of shares held in trust	**(765)**	(408)
Weighted average common shares outstanding – basic	**64,448**	62,969
Weighted average common shares outstanding – diluted[(1)]	**74,798**	69,989
Net income per share – basic	**$ 0.69**	$ 1.29
Net income per share – diluted	**$ 0.59**	$ 1.16

(1) For the year ended December 31, 2022, 4.3 million potentially issuable common shares through the share-based compensation plan were excluded as they were not dilutive (year ended December 31, 2021 - 8.8 million).

18. SHARE-BASED PAYMENTS

The components of share-based payment expense are as follows:

		December 31, 2022		December 31, 2021
Compensation awards	$	**665**	$	277
Share options		**194**		83
Performance share rights		**6,575**		1,684
Share-based payments[(1)]	**$**	**7,434**	$	2,044

(1) For the year ended December 31, 2022, the Company has recorded $1.3 million respectively, (year ended December 31, 2021 - $1.5 million) related to equity settled transactions that are expected to settle in cash.

The following tables summarize information about options, rights, and awards outstanding:

	Compensation awards					
(thousands)	**Deferred options**	**Deferred shares**	**Share options**	**Performance share rights[(1)]**	**Restricted rights**	**Total**
December 31, 2020	5,057	2,401	5,397	3,420	—	16,275
Granted	2,448	1,367	1,258	1,715	1,436	8,224
Exercised for common shares	—	—	(398)	—	(1,428)	(1,826)
Exercised for shares held in trust	(198)	(161)	—	—	—	(359)
Exercised for restricted rights	(303)	(278)	—	(855)	—	(1,436)
Performance adjustment[(4)]	—	—	—	(855)	—	(855)
Cancelled/forfeited	(1,090)	(151)	(455)	(360)	(8)	(2,064)
Expired	(438)	(20)	(1,725)	—	—	(2,183)
December 31, 2021	5,476	3,158	4,077	3,065	—	15,776
Granted[(2)]	1,457	792	1,298	833	3,125	7,505
Exercised for common shares	—	—	(49)	—	(3,125)	(3,174)
Exercised for shares held in trust	(780)	(280)	—	—	—	(1,060)
Exercised for restricted rights	—	(760)	—	(2,365)	—	(3,125)
Performance adjustment[(3)]	—	—	—	1,014	—	1,014
Cancelled/forfeited	(267)	(42)	(1,725)	—	—	(2,034)
December 31, 2022	**5,886**	**2,868**	**3,601**	**2,547**	**—**	14,902

(1) Certain performance share rights contain monetary awards that may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Board of Directors, equal to the monetary amount at the time of vesting. These awards are accounted for as cash-settled share-based payments in which the fair value of the amounts payable under the plan are recognized incrementally as an expense over the vesting period, with a corresponding change in liabilities. As at December 31, 2022, nil has been accrued pursuant to cash-settled share-based payment awards (December 31, 2021 – $0.3 million).

(2) During the year ended December 31, 2022, 1.5 million deferred options, 0.8 million deferred shares, 1.3 million share options, 0.8 million performance share rights, and 3.1 million restricted rights were granted to Officers, Directors, and employees of the Company.

(3) Performance share rights are subject to a performance multiplier of 0.5 to 2.0.

During the year ended December 31, 2022, the Company granted 4.4 million share-based payment awards, comprised of deferred options, deferred shares, share options, and performance share rights (2021 – 6.8 million). The Company used the Black Scholes pricing model to calculate the estimated fair value of the outstanding deferred options (note 18(a)) and share options (note 18(b)) at the date of grant. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

	2022	2021
Dividend yield (%)	**0.0**	0.0
Forfeiture rate (%)	**5.0-10.0**	5.0-10.0
Expected volatility (%)	**60.0**	60.0
Risk-free interest rate (%)	**2.2-3.2**	0.6-0.9
Expected life (years)	**3.2-3.4**	3.2-3.4
Vesting period (years)	**4.0**	4.0
Contractual life (years)	**5.0**	5.0
Weighted average share price at grant date	**1.04**	0.31-0.35
Weighted average fair value at grant date	**1.07-1.08**	0.13-0.14

During the year ended December 31, 2022, 2.4 million restricted rights were issued in exchange for the exercise of performance share rights (2021 – 0.9 million), 0.8 million in exchange for the exercise of deferred shares (2021 – 0.3 million), and nil in exchange for deferred options (2021 – 0.3 million).

a) Compensation awards

Deferred options

The Company has deferred option agreements in place with certain employees whereby they may be entitled to receive shares of the Company purchased on the open market by an independent trustee if they remain employees of the Company during such time and exercise their options. Deferred options generally vest one quarter on each year of the term, with expiry occurring five years after issuance. The shares purchased by the independent trustee are reported as shares held in trust (note 18(b)).

The following table summarizes information about the deferred options and performance-based long-term incentive awards outstanding:

	Deferred options outstanding			Deferred options exercisable	
Range of exercise prices	**Number of deferred options (thousands)**	**Average contractual life (years)**	**Weighted average exercise price ($/share)**	**Number of deferred options (thousands)**	**Weighted average exercise price ($/share)**
$0.00 to $0.29	3,466	2.2	0.05	1,640	0.04
$0.30 to $0.48	929	3.7	0.34	213	0.34
$0.49 to $1.33	1,491	4.6	1.00	—	—
Total	5,886	3.2	0.32	1,853	0.08

There were 1.5 million deferred options granted during 2022 (2021 - 2.4 million).

Deferred shares

The Company also has deferred share agreements in place with directors and certain employees whereby, in the case of directors, upon retirement from the Board of Directors, or in the case of employees, over a period of two years if they remain employees of the Company during such time, may be entitled to receive at the discretion of the Board of Directors, cash, a grant of restricted rights (note 18(d)), or shares of the Company purchased on the open market by an independent trustee. The shares purchased by the independent trustee are reported as shares held in trust (note 18(b)).

The fair value of these awards is assessed on the grant date by factoring in the weighted average common share trading price for the five days preceding the grant date and is reduced by an estimated forfeiture rate of 5% (2021 – 5%). The fair value is recognized as share-based payment expense over the vesting period with a corresponding increase to contributed surplus. Upon exercise of these agreements in exchange for restricted rights, the value in contributed surplus pertaining to the exercise is recorded as share capital. Upon exercise of these agreements in exchange for shares held in trust, the shares held in trust account is reduced by the number of shares issued using the average cost base of purchased shares and offset to contributed surplus.

The estimated average value of deferred shares at the time of grant during the year ended December 31, 2022 was $1.07 per deferred share (2021 – $0.34).

b) Share options

Perpetual’s share option plan provides a long-term incentive to executive officers and directors associated with the Company’s long-term performance. The Board of Directors administers the share option plan and determines participants, number of share options and terms of vesting. The exercise price of the share options granted shall not be less than the value of the weighted average trading price for the Company’s common shares for the five trading days immediately preceding the date of grant. Share options granted vest evenly over four years, with expiry occurring five years after issuance.

The following table summarizes information about share options outstanding:

	Options outstanding			Options exercisable	
Range of exercise prices	**Number of share options (thousands)**	**Average contractual life (years)**	**Weighted average exercise price ($/share)**	**Number of share options (thousands)**	**Weighted average exercise price ($/share)**
$0.07 to $0.30	1,436	2.0	0.17	827	0.19
$0.31 to $0.75	867	3.6	0.34	217	0.34
$0.76 to $1.33	1,298	4.6	1.04	—	—
Total	3,601	3.3	0.53	1,044	0.22

There were 1.3 million share options granted during 2022 (2021 – 1.3 million)

c) Performance share rights

The Company has an equity-settled performance share rights plan for the Company’s executive officers. Performance rights granted under the performance share rights plan vest two years after the date upon which the performance rights were granted. The performance rights that vest and become redeemable are a multiple of the performance rights granted, dependent upon the achievement of certain performance metrics over the vesting period. Vested performance rights can be settled in cash or restricted rights (note 18(d)), at the discretion of the Board of Directors. Performance rights are forfeited if participants of the performance share rights plan leave the organization other than through retirement or termination without cause prior to the vesting date.

The fair value of a performance share rights award is determined at the date of grant by using the closing price of common shares and multiplied by the estimated performance multiplier. As at December 31, 2022, performance multipliers of 2.0 and 1.2 have been assumed for unvested awards granted in 2021 and 2022, respectively. Fluctuations in share-based payments may occur due to changes in estimates of performance outcomes. The amount of share-based payment expense is reduced by an estimated forfeiture rate of 5% (2021 – 5%) for outstanding awards. The estimated value of performance share rights granted during the year ended December 31, 2022 was $0.97 per performance share right (2021 – $0.23).

In 2018, the Company introduced a performance-based long-term incentive awards plan (the "PLTI" plan) for the executive officers. The awards granted pursuant to the plan are tied to specific individual-based performance metrics established by the Board which can be based on "total shareholder return" or other metrics specifically designed to align with value creation for shareholders and to incentivize and retain key executive officers. The awards vest evenly over four years, with expiry occurring five years after issuance. Upon vesting, award holders may be entitled to receive, at the discretion of the Board of Directors, cash, a grant of restricted rights (note 18(d)), or a combination of cash and restricted rights.

Certain awards granted under the PLTI plan contain monetary awards that may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Board of Directors, equal to the monetary amount at the time of vesting. These awards are accounted for as cash-settled share-based compensation in which the fair value of the amounts payable under the plan are recognized incrementally as an expense over the vesting period, with a corresponding change in liabilities. Upon exercise of these awards in exchange for cash, the liability is reduced. Upon exercise of these awards in exchange for a variable number of shares, the value in liabilities pertaining to the exercise is recorded as share capital. In 2022, the Company made payments of $1.3 million (2021 – $1.3 million) pursuant to cash-settled share-based payment awards. As at December 31, 2022, nil had been accrued pursuant to cash-settled share-based compensation awards (December 31, 2021 – $0.3 million).

d) Restricted rights

The Company has a restricted rights plan for certain officers, employees and consultants. Restricted rights granted under the restricted rights plan may be exercised during a period (the "Exercise Period") not exceeding five years from the date upon which the restricted rights were granted. The restricted rights typically vest on a graded basis over two years. At the expiration of the Exercise Period, any restricted rights which have not been exercised shall expire. Upon vesting, the plan participant is entitled to receive one common share for each right held at a cost of $0.01 per share.

The fair value of an award granted under the restricted rights plan is assessed on the grant date by factoring in the weighted average common share trading price for the five days preceding the grant date. This fair value is recognized as share-based payment expense over the vesting period with a corresponding increase to contributed surplus. During the year ended December 31, 2022, the Company did not grant any restricted rights to employees, other than to settle performance share rights and deferred shares.

Restricted rights granted upon the exercise of performance share rights (note 18(c)) vest on the grant date and have a 90-day exercise period. Restricted rights granted upon the exercise of deferred compensation awards (note 18(a)) vest on the grant date and have a 30-day exercise period. No value is assigned to restricted rights issued pursuant to those plans as the value and expense have been previously recognized over the vesting period of the underlying performance share rights and deferred compensation awards.

19. REVENUE

The Company sells its production pursuant to fixed or variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location, or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of conventional natural gas, heavy crude oil or NGL as may be applicable to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

Conventional natural gas, heavy crude oil and NGL are mostly sold under contracts of varying price and volume terms of up to one year. Revenues are typically collected on the 25th day of the month following production.

Natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations and priced at daily index prices, less transportation costs from AECO, to each market price point as detailed in the table below.

Market/Pricing Point	**January 1, 2023 to October 31, 2023 Daily sales volume *(MMBtu/d)***	**November 1, 2023 to October 31, 2024 Daily sales volume *(MMBtu/d)***
Malin	—	15,000
Dawn	15,000	15,000
Emerson	10,000	10,000
Total sales volume obligation	**25,000**	**40,000**

The following table presents the Company's oil and natural gas sales disaggregated by revenue source:

	December 31, 2022	December 31, 2021
Oil and natural gas revenue		
Natural gas	**$ 66,781**	$ 33,012
Oil	**29,538**	20,172
NGL	**13,368**	7,630
Total oil and natural gas revenue	**$ 109,687**	$ 60,814

Included in accounts receivable at December 31, 2022 is $10.0 million of accrued oil and natural gas revenue related to December 2022 production (December 31, 2021 – $7.0 million related to December 2021 production).

20. FINANCE EXPENSE

The components of finance expense are as follows:

		December 31, 2022		December 31, 2021
Cash finance expense				
Interest on revolving bank debt	$	**1,031**	$	953
Interest on term loan		**216**		53
Interest on 2025 Senior Notes(1)		**3,184**		1,408
Interest on 2022 Senior Notes(2)		**—**		(1,253)
Interest on lease liabilities (note 14)		**116**		148
Total cash finance expense		**4,547**		1,309
Non-cash finance expense				
Interest paid in-kind on term loan (note 10)		**—**		2,743
Interest paid in-kind on 2022 Senior Notes (note 12)(1)		**—**		1,469
Interest paid in-kind on 2025 Senior Notes (note 12)(2)		**—**		1,533
Gain on senior note maturity extension (note 12)		**—**		(1,591)
Gain on senior note extinguishment (note 12)(3)		**(101)**		—
Gain on Second Lien Loan Settlement(4)		**—**		(6,820)
Amortization of debt issue costs		**1,864**		962
Accretion on decommissioning obligations (note 15)		**727**		531
Change in fair value of other liability (note 11)		**1,678**		1,159
Change in fair value of royalty obligations (note 13)		**2,256**		4,101
Total non-cash finance expense		**6,424**		4,087
Finance expense recognized in net income	**$**	**10,971**	$	5,396

(1) The Company satisfied the January 23, 2022 and July 23, 2022 semi-annual interest payment of $1.6 million by making cash payments.

(2) On January 22, 2021, Perpetual's 2022 Senior Notes were exchanged for 2025 Senior Notes, providing Perpetual the option to pay interest in-kind. Perpetual elected to pay the January 23, 2021 semi-annual interest of $1.5 million by a PIK Interest Payment. As a result, the previously accrued 2022 Senior Notes cash interest of $1.3 million was reversed and replaced by $1.3 million of 2025 Senior Note non-cash interest expense.

(3) During the year ended December 31, 2022 the Company extinguished $0.9 million of Senior Notes outstanding for a total cost of $0.8 million, resulting in a gain on extinguishment of $0.1 million.

(4) On September 3, 2021, upon completion of the Plan of Arrangement, Perpetual's Term Loam was substantively modified pursuant to the Second Lien Loan Settlement which included payment of $38.5 million, delivery of 0.7 million Rubellite shares valued at $1.4 million, the entry into a new second lien term loan of $2.7 million, and a contingent payment obligation valued at $0.2 million resulting in a gain of $6.8 million.

(5) Pursuant to the terms of the Second Lien Loan Settlement, $0.2 million has been earned related to the 2021 payment cap and $1.3 million has been earned related to the 2022 payment cap. Perpetual is committed to pay up to an additional $1.9 million in potential contingent payments in the event that Perpetual's annual average realized crude oil and natural gas prices exceed certain thresholds. The change in fair value of this liability was recorded in the statement of comprehensive income as a non-cash finance expense.

21. CHANGES IN NON-CASH WORKING CAPITAL INFORMATION

		December 31, 2022		December 31, 2021
Accounts receivable	$	**(4,133)**	$	(7,718)
Prepaid expenses and deposits		**(654)**		(38)
Change in non-cash working capital on disposition and other		**—**		5,426
Inventory		**(387)**		—
Accounts payable and accrued liabilities		**(13,261)**		20,299
Change in non-cash working capital	**$**	**(18,435)**	$	17,969

The change in non-cash working capital has been allocated to the following activities:

		December 31, 2022		December 31, 2021
Operating	$	**(9,442)**	$	3,406
Investing		**(8,993)**		14,563
Change in non-cash working capital	**$**	**(18,435)**	$	17,969

22. FINANCIAL RISK MANAGEMENT

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework and has implemented and monitors compliance with risk management policies.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners, oil and natural gas marketers and derivative contract counterparties.

Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following sales. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large, well established purchasers. The Company historically has not experienced any significant collection issues with its oil and natural gas marketing receivables. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, the receivables are generally from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling, and oil and natural gas production; in addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venture partners, however, the Company does have the ability in some cases to withhold production or amounts payable to joint venture partners in the event of non-payment.

The Company manages the credit exposure related to derivatives by engaging in risk management transactions with credit worthy counterparties, and periodically monitoring counterparty credit assessments.

The combined carrying amount of cash and cash equivalents, accounts receivable and fair value of derivative assets at December 31, 2022 was $19.7 million (December 31, 2021 – $13.4 million), representing the Company's maximum credit exposure. The Company's credit provisions are represented by its loss allowance based on lifetime expected credit losses as at December 31, 2022 of $0.1 million (December 31, 2021 – $0.4 million). The amount of the loss allowance was determined based on historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. The total amount of accounts receivables 90 days past due is nominal as at December 31, 2022 (December 31, 2021 – nominal).

b) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking harm to the Company's reputation.

c) Market risk

Market risk is the risk that changes in market prices such as foreign exchange rates, commodity prices and interest rates will affect the Company's net income (loss) or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company utilizes both financial derivatives and fixed price physical delivery sales contracts to manage market risks related to commodity prices and foreign currency rates. All such transactions are conducted in accordance with the Company's Risk Management Policy, which has been approved by the Board of Directors.

i) Commodity price risk

Commodity price risk is the risk that the fair value or future cash flow will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollar, but also by world economic events that dictate the levels of supply and demand. The Company manages commodity price risk using various financial derivatives and fixed price physical delivery sales contracts.

Natural gas contracts

At December 31, 2022 the Company had entered into the following natural gas risk management contracts at AECO:

Commodity	Volumes sold	Term	Reference/Index	Contract Traded Bought/sold	Market Price
Natural gas	5,000 GJ/d	Jan 1 - Mar 31, 2023	AECO 5A (CAD$/GJ)	Swap - sold	$4.62
Natural gas	5,000 GJ/d	Jan 1 - Mar 31, 2023	AECO 7A (CAD$/GJ)	Collar	$7.00-8.00
Natural gas	10,000 GJ/d	Jan 1 - Mar 31, 2023	AECO 7A (CAD$/GJ)	Collar	$7.00-8.10

Subsequent to December 31, 2022, the Company has entered into the following natural gas risk management contracts::

Commodity	Volumes sold	Term	Reference/Index	Contract Traded Bought/Sold	Market Price
Natural gas	5,000 GJ/d	Feb 1 - Feb 28, 2023	AECO 7A (CAD$/GJ)	Swap - sold	$4.02
Natural gas	2,500 GJ/d	Mar 1 - Mar 31, 2023	AECO 7A (CAD$/GJ)	Swap - sold	$3.55

Natural gas contracts - sensitivity analysis

As December 31, 2022, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, net income for the period would change by $0.1 million due to changes in the fair value of risk management contracts. Fair value sensitivity was based on published forward AECO prices.

Oil contracts

At December 31, 2022, the Company had entered the following oil risk management contracts which settle in CAD$:

Commodity	Volumes sold	Term	Reference/ Index	Contract Traded Bought /sold	Market Price
Crude oil	100 bbl/d	Jan 1 - Dec 31, 2023	WTI (USD$/bbl)	Swap - sold	$89.15
Crude oil	100 bbl/d	Jan 1 – Dec 31, 2023	WCS (CAD$/bbl)	Differential	($17.30)

Subsequent to December 31, 2022, the Company has entered into the following natural gas risk management contracts:

Commodity	Volumes sold	Term	Reference/ Index	Contract Traded Bought /sold	Market Price
Crude oil	200 bbl/d	Apr 1 - Dec 31, 2023	WTI (USD$/bbl)	Swap - sold	$77.40
Crude oil	200 bbl/d	Apr 1 - Dec 31, 2023	WCS (USD$/bbl)	Differential	($17.40)
Crude oil	250 bbl/d	Apr 1 – Dec 31, 2023	WCS (USD$/bbl)	Differential	($17.45)

Oil contracts - sensitivity analysis

As at December 31, 2022, if future WTI oil prices changed by CAD$5.00 per bbl with all other variables held constant, net income for the period would change by $0.2 million due to changes in the fair value of risk management contracts.

Foreign exchange contracts

At December 31, 2022, the Company had entered the following CAD/USD foreign exchange swaps which settle in CAD$:

Contract	Notional amount	Term	Price (US$/CAD$)
Average rate forward (US$/CAD$)	$316,444 US$/month	Jan 1 – Mar 31, 2023	1.3740
Average rate forward (US$/CAD$)	$250,000 US$/month	Jan 1 – Dec 31, 2023	1.3600
Average rate forward (US$/CAD$)	$200,000 US$/month	Jan 1 – Dec 31, 2023	1.3029
Average rate forward (US$/CAD$)	$500,000 US$/month	Jan 1 – Dec 31, 2023	1.3710

As at December 31, 2022, if future USD/CAD exchange rates changed by CAD$0.05 with all other variables held constant, net income for the period would change by $0.7 million due to changes in the fair value of risk management contracts.

Foreign exchange contracts - sensitivity analysis

The following table summarizes the risk management contracts by type:

		December 31, 2022		December 31, 2021
Natural gas contracts		**2,841**		682
Foreign exchange contracts		**30**		—
Oil contracts		**976**		(321)
Risk management contracts	**$**	**3,847**	$	361
Risk management contracts – current asset		**3,847**		682
Risk management contracts – current liability		**—**		(321)
Risk management contracts	**$**	**3,847**	$	361

The following table details the gains (losses) on risk management contracts:

		December 31, 2022		December 31, 2021
Unrealized gain (loss) on foreign exchange contracts	**$**	**30**	$	—
Unrealized gain (loss) on natural gas contracts		**2,159**		4,033
Unrealized gain (loss) on oil contracts		**1,298**		(300)
Unrealized gain (loss) on fair value of derivatives		**3,487**		3,733
Realized gain (loss) on natural gas contracts		**(491)**		(4,748)
Realized gain (loss) on oil contracts		**(4,129)**		(62)
Realized gain (loss) on financial derivatives		**(4,620)**		(4,810)
Change in fair value of derivatives	**$**	**(1,133)**	$	(1,077)

Fair value of financial assets and liabilities

The Company's fair value measurements are classified into one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forecasted commodity prices.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation.

The fair value of cash and cash equivalents, accounts receivable, prepaid expenses and deposits, and accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. The Credit Facility bears interest at a floating market rate, and accordingly, the fair market value approximates the carrying amount.

The fair value of the other liability is estimated by discounting future cash payments based on Perpetual's annual average realized oil and natural gas prices exceeding certain thresholds. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and Perpetual's forecasted annual average realized oil and natural gas prices, are used in determination of the carrying amount. A discount rate of 8.1% was determined on inception of the agreement based on the characteristics of the instrument.

The fair value of the royalty obligations is estimated by discounting future cash payments based on the forecasted natural gas and NGL commodity prices multiplied by the royalty volumes. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and forecasted natural gas and NGL commodity prices, are used in determination of the carrying amount. Discount rates of 12.0% to 12.2% were determined on inception of the agreements based on the characteristics of the instruments.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels:

				Fair value		
As at December 31, 2022	**Gross**	**Netting[1]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Marketable securities	1,814	—	1,814	—	1,814	—
Risk management contracts	3,970	(123)	3,847	—	3,847	—
Financial liabilities						
Financial liabilities at amortized cost						
Revolving bank debt	(14,909)	—	(14,909)	(14,909)	—	—
Senior notes	(34,527)	—	(34,527)	—	(34,527)	—
Term loan	(2,524)	—	(2,524)	—	—	(2,524)
Fair value through profit and loss						
Other liability	(3,002)	—	(3,002)	—	—	(3,002)
Risk management contracts	(123)	123	—	—	—	—

(1) Risk management contract assets and liabilities presented in the condensed interim consolidated statements of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right, and intention for net settlement exists.

				Fair value		
As at December 31, 2021	**Gross**	**Netting[1]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Marketable securities	2,409	—	2,409		2,409	—
Risk management contracts	775	(93)	682	—	682	—
Financial liabilities						
Financial liabilities at amortized cost						
Revolving bank debt	(2,487)	—	(2,487)	(2,487)	—	—
Senior notes	(34,189)	—	(34,189)	—	(34,189)	—
Term loan	(2,469)	—	(2,469)	—	—	(2,469)
Fair value through profit and loss						
Other liability	(1,387)	—	(1,387)	—	—	(1,387)
Risk management contracts	(414)	93	(321)	—	(321)	—
Royalty obligations	(4,697)	—	(4,697)	—	—	(4,697)

(1) Risk management contract assets and liabilities presented in the condensed interim consolidated statements of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right, and intention for net settlement exists.

d) Capital risk

The Company's policy is to maintain a strong but flexible capital structure so as to maintain investor, creditor and market confidence and to sustain its future development. The Company manages its capital structure and adjusts it in light of changes in economic conditions. The Company's capital structure consists of shareholders' equity and working capital. The Company has access to its $30.0 million first lien credit facility with a syndicate of lenders, under which $14.9 million was drawn (December 31, 2021 – $17.0 million) and $1.2 million of letters of credit had been issued (December 31, 2021 – $1.0 million).

23. DEFERRED INCOME TAXES

The provision for income taxes in the consolidated financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Company's net income before income tax. This difference results from the following items:

		December 31, 2022		December 31, 2021
Net income before income tax	**$**	**28,503**	$	81,121
Combined federal and provincial tax rate		**23.0 %**		23.0 %
Computed income tax expense		**6,556**		18,658
Increase (decrease) in income taxes resulting from:				
Non-deductible expenses		**1,422**		162
Non-taxable capital (gain) loss		**73**		(952)
Other		**(471)**		218
Change in tax rates and unrecognized tax assets		**(23,474)**		(18,086)
Deferred tax (recovery)	**$**	**(15,894)**	$	—

The following table summarizes the deferred tax liabilities of the Company and its subsidiaries, which are offset against certain deferred tax assets:

		December 31, 2022		December 31, 2021
Liabilities:				
Property, plant and equipment	**$**	**(27,798)**	$	(28,187)
Senior notes		**(257)**		(550)
Term loan		**(34)**		(46)
Revolving bank debt		**—**		(118)
Share investment		**(194)**		(262)
Fair value of derivatives		**(884)**		(157)
Right-of-use-assets		**(199)**		(262)
Total deferred tax liabilities		**(29,366)**		(29,582)
Assets:				
Decommissioning obligations	**$**	**6,314**	$	7,573
Lease liabilities		**362**		484
Royalty obligations		**—**		1,080
Share and debt issue costs		**364**		548
Fair value of derivatives		**—**		74
Other liabilities		**690**		319
Non-capital losses		**37,530**		19,504
Total deferred tax assets		**45,260**		29,582
Net deferred tax asset	**$**	**15,894**	$	—

The unused tax losses and deductible temporary differences included in the Company's unrecognized deferred tax assets are as follows:

For the years ended		**December 31, 2022**		December 31, 2021
Non-capital losses	**$**	**—**	$	100,923
Capital losses		**158,294**		219,345
	$	**158,294**	$	320,268

As at December 31, 2022, the Company had approximately $163.2 million (December 31, 2021 – $187.9 million) of non-capital losses available for future use. The unused non-capital losses expire between 2036 and 2042, and unused capital losses have no expiry date. The development and production assets and facilities owned by the Company and its subsidiaries have an approximate tax basis of $57.6 million (December 31, 2021 – $38.0 million) available for future use as deductions from taxable income, as indicated below:

Resource Tax Pools		**December 31, 2022**		December 31, 2021
Canadian oil & gas property expense	**$**	**4,483**	$	2,968
Canadian development expense		**33,368**		11,249
Canadian exploration expense		**—**		238
Undepreciated capital cost		**19,773**		23,525
	$	**57,624**	$	37,980

Deferred tax assets have not been recognized in respect of capital losses because it is not probable that future taxable capital gains will be available against which the Company can utilize the benefits.

24. KEY MANAGEMENT PERSONNEL

The Company has defined key management personnel as executive officers, as well as the Board of Directors, as they have the collective authority and responsibility for planning, directing and controlling the activities of the Company. The following table outlines the total compensation expense for key management personnel:

For the years ended		**December 31, 2022**		December 31, 2021
Short-term compensation	**$**	**4,792**	$	2,074
Share-based payments		**1,527**		1,547
	$	**6,319**	$	3,621

25. RELATED PARTIES

During the year ended December 31, 2022 Perpetual billed and/or incurred on behalf of Rubellite net transactions, which are considered to be normal course of oil and gas operations, totaling $5.6 million (December 31, 2021 - $1.4 million). Included within this amount are $1.9 million (December 31, 2021 - $0.4 million) of costs billed under the MSA. The Company recorded an accounts receivable of $0.6 million owing from Rubellite as at December 31, 2022 (December 31, 2021 - accounts payable of $0.1 million).

Investments made in entities directed or controlled by the Company's CEO were revalued to $0.4 million at December 31, 2022 (December 31, 2021 - nominal). There were no amounts outstanding or receivable at December 31, 2022 (December 31, 2021 - nil).

26. SUPPLEMENTAL DISCLOSURE

The Company’s consolidated statements of income and comprehensive income are prepared primarily by nature of expense, except for employee compensation costs which are included in both production and operating and general and administrative expenses.

The following table details the amount of total employee compensation costs included in production and operating and general and administrative expenses in the consolidated statements of income and comprehensive income.

For the years ended		**December 31, 2022**		December 31, 2021
Production and operating	**$**	**1,335**	$	1,198
General and administrative		**8,523**		5,145
Share-based payments		**7,434**		2,044
	$	**17,292**	$	8,387

DIRECTORS

Susan L. Riddell Rose
President, Chief Executive Officer and Director

Linda A. Dietsche
Independent Director(1)(2)(3)(4)

Geoffrey C. Merritt
Independent Director(1)(2)(3)(4)

Ryan A. Shay
Vice President, Finance and Chief Financial Officer and Director

Steven L. Spence
Independent Director(1)(2)(3)(4)

Howard R. Ward
Independent Director(1)(2)(3)(4)

(1) Member of Audit Committee
(2) Member of Reserves Committee
(3) Member of Compensation and Corporate Governance Committee
(4) Member of Environmental, Health & Safety Committee

OFFICERS

Susan L. Riddell Rose
President, Chief Executive Officer and Director

Ryan A. Shay
Vice President, Finance and Chief Financial Officer and Director

Ryan M. Goosen
Vice President, Business Development and Land

Jeffrey R. Green
Vice President, Corporate and Engineering Services

Linda L. McKean
Vice President, Production and Development

Marcello M. Rapini
Vice President, Marketing

Karl H. Rumpf
Vice President, Exploration and New Ventures

HEAD OFFICE

3200, 605 – 5 Avenue SW
Calgary, Alberta Canada T2P 3H5

403.269.4400 PHONE
800.811.5522 TOLL FREE
403.269.4444 FAX
info@perpetualenergyinc.com EMAIL
www.perpetualenergyinc.com WEB

STOCK EXCHANGE LISTING | TSX | PMT

AUDITORS

KPMG LLP

BANKERS

ATB Financial
Bank of Montreal
Bank of Nova Scotia

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company

PERPETUAL ENERGY

www.perpetualenergyinc.com

3200, 605 – 5 Avenue SW
Calgary, Alberta CANADA T2P 3H5

800.811.5522 TOLL FREE
403.269.4400 PHONE
info@perpetualenergyinc.com EMAIL

STOCK EXCHANGE LISTING | TSX | PMT