CLEARVIEW
RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

December 31, 2022

2022 HIGHLIGHTS

- Repaid all $8.8 million bank debt outstanding on Clearview's credit facility in 2022 with a working capital surplus of $0.7 million at the end of the year;

- Increased adjusted funds flow[(1)] by 74% to a record $9.7 million in 2022 compared to $5.6 million in 2021;

- Realized sales price for oil[(2)] increased 51% over the comparative year, to $113.47 per barrel, and the realized sales price for natural gas[(2)] increased 43% over the comparative year, to $5.56 per mcf;

- Disposed of three non-core assets in 2022 for gross proceeds of $3.2 million at $21,500 per flowing barrel of oil equivalent per day ("boe/d") (72% natural gas) reducing corporate asset retirement obligations by $0.6 million; and

- Disposed of two additional non-core assets, subsequent to the end of the year, for gross proceeds of $2.2 million at $20,000 per flowing boe/d (72% oil) reducing the Company's asset retirement obligations by an additional $2.5 million.

Notes

(1) "Adjusted funds flow" and "net debt" are capital management measures that do not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures of other entities. See "Non-IFRS Measures" contained within this MD&A.

(2) Supplementary financial measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures of other entities. See "Non-IFRS Measures" contained within this MD&A.

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The MD&A should be read in conjunction with the Company's audited financial statements and accompanying notes for the periods ended December 31, 2022 and December 31, 2021. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts in the tables are expressed in thousands of Canadian dollars ($000's), except per unit amounts, and unless otherwise noted. The MD&A has been prepared and approved by the Board of Directors as of April 25, 2023.

Refer to page 28 for information about Non-IFRS Measures, page 31 for information on forward-looking statements and page 32 for measures, conversions and acronyms used in the MD&A.

OVERVIEW OF THE COMPANY

Clearview Resources Ltd. (the "Company") is a privately owned, growth-oriented oil and natural gas producing company based in Calgary, Alberta with production and development primarily focused in the Greater Pembina area of west central Alberta. The Company is a reporting issuer with additional information about the Company available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval ("SEDAR") at www.sedar.com and on the Company's website at www.clearviewres.com.

The Company's oil and natural gas properties are listed below:

Region - Alberta	Property	Primary production	P+P Reserves[1]	Average WI	Operatorship[2]
Greater Pembina	Northville	Liquids rich natural gas	5,585	87%	Yes
	Pembina	Liquids rich natural gas	1,155	80%	Yes
	Wilson Creek	Light oil and liquids rich natural gas	3,804	60%	Yes
	Windfall	Light oil	5,447	100.0%	Yes
	Niton	Light oil	1,318	96%	Yes
	Garrington	Light oil and liquids rich natural gas	1,501	94%	Yes
	Caribou	Light oil	417	70.0%	Yes
Other	Bantry	Medium oil	181	40.0%	No
	Lindale (Unit)	Light oil with associated natural gas and liquids	136	10.6%	No
	Miscellaneous	Various	73	Various	Mixed
Total			19,617		

[1] mboe of total proved plus probable reserves at December 31, 2022 as determined by the Company's independent reserves evaluator, McDaniel & Associates Consultants Ltd.
[2] operatorship of a majority of the property

The Company's objectives continue to be:

- acquire long life, cash generating oil and natural gas properties with growth potential;
- maintain a low cost and financially robust operating structure;
- reduce the Company's bank debt leverage to a minimal level;
- build the Company's production base to fund the field capital program from internally generated funds;
- maintain a current licensee liability rating of 2.0 or greater; and
- continue pursuing non-core asset dispositions.

SELECTED ANNUAL INFORMATION

	Three months ended		Years ended		
	Dec. 31 2022	Dec. 31 2021	Dec. 31 2022	Dec. 31 2021	Dec. 31 2020
Oil and natural gas sales	8,572	8,918	41,176	30,364	16,133
Adjusted funds flow (1)	2,044	1,797	9,681	5,573	2,487
Per share – basic (1)	0.18	0.15	0.83	0.48	0.21
Per share – diluted (1)	0.18	0.14	0.83	0.44	0.21
Cash provided by operating activities	1,667	2,065	8,530	6,130	1,783
Per share – basic	0.14	0.18	0.73	0.53	0.15
Per share - diluted	0.14	0.16	0.73	0.48	0.15
Net earnings (loss)	(6,406)	10,512	(2,549)	5,212	(10,842)
Per share – basic	(0.55)	0.90	(0.22)	0.45	(0.93)
Per share – diluted	(0.55)	0.82	(0.22)	0.42	(0.93)
Total assets			55,978	73,277	70,498
Total long term liabilities			18,736	25,863	27,581
Net debt (1)			539	10,193	13,235
Capital expenditures (1)	1,156	640	3,494	2,108	376

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

For the year ended December 31, 2022, the Company’s oil and natural gas sales increased to $41.2 million due to higher realized sales prices for all its production offset by a 7% decrease in production, year over year, as a result of normal production declines. Adjusted funds flow was $9.7 million while cash provided by operating activities was $8.5 million for the year ended December 31, 2022. The net loss for 2022 was $2.5 million compared to net earnings in the prior year of $5.2 million. The loss in 2022 was primarily due to an impairment expense associated with the reclassification, to assets held for sale, of a non-operated, minor working interest property in the Central Alberta Oil CGU to its fair value less costs to sell of $1.5 million. The Company recorded a loss on the reclassification of $6.5 million. Long term liabilities decreased in the year ended December 31, 2022 due to decommissioning operations undertaken to abandon 24 gross (5.3 net) wells, the reduction of decommissioning liabilities associated with the disposition and reclassification of property, plant and equipment and a higher discount rate positively affecting the discounting of decommissioning obligations. The Company had no bank debt outstanding on December 31, 2022 as adjusted funds flow in excess of net capital expenditures and proceeds on dispositions in 2022 were used for repayment. Net debt of $0.5 million consists of a working capital surplus of $0.7 million and the convertible debentures of $1.2 million.

For the year ended December 31, 2021, the Company’s oil and natural gas sales increased to $30.4 million due to higher realized sales prices for all its production while production remained very steady year over year with a 3% increase. Adjusted funds flow was $5.6 million while cash provided by operating activities was $6.1 million for the year ended December 31, 2021. Long term liabilities decreased in the year ended December 31, 2021 due to decommissioning operations undertaken during 2021 to abandon 29 gross (13.2 net) wells and a higher discount rate positively affecting the discounting of decommissioning obligations. Net debt was reduced over the twelve months ended December 31, 2021 as adjusted funds flow in excess of net capital expenditures was applied against bank debt. Net earnings for 2021 were $5.2 million compared to a net loss in the prior year of $10.8 million. The increase in 2021 was primarily due to much higher revenues as a result of higher commodity prices and an impairment reversal of $8.3 million in the fourth quarter of 2021.

Capital expenditures

	Three months ended			Year ended		
	Dec. 31 2022	Dec.31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Land	-	22	(100)	3	143	(98)
Drilling, completions, equipping	272	338	(20)	2,157	1,288	67
Facilities	898	307	193	1,334	676	97
Other	(14)	(27)	(48)	-	1	(100)
Capital expenditures (1)	1,156	640	81	3,494	2,108	66
Disposition of properties	(1,629)	-	100	(2,979)	-	100
Net capital expenditures (1)	(473)	640	(174)	515	2,108	(76)

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

The Company spent approximately 36% of its adjusted funds flow on capital expenditures in the year ended December 31, 2022. The capital expenditures incurred were primarily for facility upgrades and well workovers and optimizations as part of an approved well reactivation/optimization program. The increase in spending of 67% in drilling, completions and equipping, over the comparative year, was undertaken due to the success of the 2021 program, the improved financial position of the Company and the stronger commodity price environment in 2022.

During the second quarter of 2022, Clearview disposed of lands, which it had acquired in 2021, in the Jarvie area of Alberta, for proceeds of $1.4 million. The Company recorded a gain on the disposition of $1.2 million. The proceeds were immediately applied to reduce the Company’s outstanding bank debt.

During the fourth quarter of 2022, the Company closed the disposition of two non-operated minor working interest properties in its Central Alberta Gas CGU for net proceeds of $1.6 million. A gain of $14 thousand was recorded in earnings related to the dispositions. The dispositions resulted in a reduction of $0.6 million in decommissioning obligations. The Company recorded transaction costs of $82 thousand related to the dispositions in the fourth quarter of 2022.

Effective December 31, 2022, the Company reclassified, to assets held for sale, a non-operated minor working interest property in its Central Alberta Oil CGU to its net recoverable amount of $1.5 million. The Company recorded a loss on the disposition of $6.5 million. The reclassification included $1.4 million in decommissioning obligations being recorded as liabilities held for sale.

Production

Production is summarized in the following table:

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Oil – bbl/d	393	433	(9)	427	462	(8)
Natural gas liquids – bbl/d	402	487	(17)	472	464	2
Total liquids – bbl/d	795	920	(14)	899	926	(3)
Natural gas – mcf/d	6,125	6,755	(9)	6,492	7,158	(9)
Total – boe/d	1,816	2,045	(11)	1,981	2,119	(7)

Production for the three months ended December 31, 2022, decreased by 11%, versus the respective comparative period. The decrease in production was due to lower oil production of 9% as a result of natural declines and periods of extreme cold weather in the quarter and lower natural gas production of 9% due to natural declines, the sale of a non-operated property during the quarter and extreme cold weather late in 2022. Natural gas liquids, generally associated with natural gas production, decreased 17% for the quarter ended December 31, 2022 versus the comparative period. The decrease was due to the disposition during the quarter and lower natural gas production.

For the year ended December 31, 2022, natural gas liquids production was higher by 2% than the comparative period primarily due to changing natural gas processing for a portion of the Company's natural gas production. The current facility extracts greater ethane volumes while processing the natural gas. Oil and natural gas production for the year ended December 31, 2022 were down 8% and 9%, respectively, over the comparative period of 2021. Total production for the year ended December 31, 2022 was lower by 7% at 1,981 boe/d versus the comparative period of 2021 as the increase in natural gas liquids production partially offset the decline in oil and natural gas production.

Clearview's production portfolio for the year ended December 31, 2022 was weighted 22% to oil, 24% to natural gas liquids and 54% to natural gas. For the year ended December 31, 2021 the production mix was weighted 22% to oil, 22% to natural gas liquids and 56% to natural gas. The change in production mix of the Company year over year has primarily been influenced by the change in natural gas processing.

Benchmark prices and economic parameters

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	82.63	77.17	7	94.23	67.96	39
Oil – Edmonton Par ($/bbl)	109.99	93.30	18	120.20	80.29	50
Differential – Light oil ($/bbl) [1]	(2.18)	(3.87)	(44)	(2.20)	(4.85)	(55)
NGLs - Pentane ($/bbl)	115.47	100.14	15	121.28	85.93	41
NGLs – Butane ($/bbl)	54.96	81.84	(33)	61.69	51.74	19
NGLs – Propane ($/bbl)	39.07	58.44	(33)	50.05	43.39	15
Natural gas – AECO ($/mcf)	5.10	4.65	10	5.31	3.62	47
Exchange rate – US$/Cdn$	0.737	0.794	(7)	0.769	0.798	(4)

(1) The light oil differential is calculated as WTI in Canadian dollars minus the Edmonton Par price.

The refiners' posted prices for Canadian crude oils are influenced by the WTI reference price, transportation capacity and costs, US$/Cdn$ exchange rates and the supply/demand situation of particular crude oil quality streams during the period. Benchmark oil prices in the three months ended December 31, 2022 increased 7% from an average of US $77.17 per barrel in 2021 to US $82.63 per barrel in 2022. Global oil demand continues to be strong in most regions with oil and refined product inventories continuing to decline and below normal levels for this time of year in most regions. The Russian invasion of Ukraine has put Russian production at risk and it is likely to continue to drop as many countries turn away from Russian oil. OPEC continued to return production to the market and by September the quotas were back to their original levels. Many OPEC nations are not meeting their production quotas and it appears only Saudi Arabia and a couple of other core members have some production capacity remaining. With prices softening in September, OPEC decided to cut quotas again to defend oil prices. Total US production has been growing but at a moderate pace as shale producers continue to show discipline in their capital programs. Despite the strong structural setup for commodity prices, the ongoing risk of a recession could have a material impact on prices. Canadian oil prices increased by 18% in the three months ended December 31, 2022, compared to the same quarter in 2021, as the light oil differential narrowed by 44% over the same comparative quarter, on top of the increase in WTI.

Benchmark oil prices for the year ended December 31, increased from an average of US $67.96 per barrel in 2021 to US $94.23 per barrel in 2022, resulting in a 39% increase. Canadian oil prices increased by 50% in the year ended December 31, 2022 compared to the same period in 2021 as the

Canadian light oil differential or discount narrowed by 55% over the same comparative period on top of the increase in WTI.

Pentane prices increased over the three months and year ended December 31, 2022 in a very similar manner to WTI pricing and Canadian light oil prices, with increases of 15% and 41%, respectively, versus the comparative periods of 2021.

Butane prices averaged $54.96 per barrel for the quarter ended December 31, 2022, a decrease of 33% from the same quarter of 2021. Butane prices averaged $61.69 per barrel for the year ended December 31, 2022, an increase of 19% from the same period of 2021. The recovery in butane prices over 2022 versus the same period in 2021 is largely due to increased demand for the product with the recovery of the North American economy and the rise in WTI prices.

Propane prices averaged $39.07 per barrel for the quarter ended December 31, 2022, a decrease of 33% compared to the same quarter of 2021. Propane prices averaged $50.05 per barrel for the year ended December 31, 2022, an increase of 15% from the same period of 2021. With continued higher US exports of propane, Canadian propane prices have increased similarly as Canadian exports continue to increase as well, keeping storage levels in Canada at a reasonable level.

AECO natural gas prices averaged $5.10 per mcf for the three months ended December 31, 2022, an increase of 10% as compared to the same quarter of 2021. For the year ended December 31, 2022, AECO natural gas prices are higher by 47% than the comparative period of 2021. AECO pricing was very strong throughout 2022 due to the low supply of natural gas going into storage in Alberta and the continued build out of export capacity from Western Canada.

Realized sales prices

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Oil – $/bbl	101.75	87.55	16	113.47	75.18	51
NGLs – $/bbl	53.22	52.61	1	59.81	44.23	35
Natural gas – $/mcf	5.19	4.95	5	5.56	3.90	43
Total – $/boe	51.30	47.39	8	56.95	39.26	45

Realized prices primarily vary from the benchmark prices due to quality differences, including differences for density and sulphur content. The differential can vary considerably from quarter to quarter. During the three months ended December 31, 2022, the Company's realized oil price was higher by 16% than the comparative quarter as a result of an 18% increase in Edmonton Par benchmark pricing. The increase in realized oil price of 51% for the year ended December 31, 2022 is consistent with the 50% increase in the Edmonton Par benchmark pricing over the prior year.

Natural gas liquids prices were higher by 1% in the fourth quarter of 2022 and higher by 35% for the current year versus the comparative periods of 2021. This increase over the comparative year was primarily due to higher prices received for all the Company's ethane, propane, butane and pentane production as a result of the increase in WTI.

The Company's realized price for natural gas was higher by 5% for the three months ended December 31, 2022. This compares to a 10% increase in the benchmark AECO price over the same period. For the majority of the Company's natural gas production, the Company receives AECO plus a slightly positive adjustment for heating content from natural gas liquids left in the natural gas stream. For the year ended December 31, 2022, the realized natural gas price increased by 43%, compared to the prior year, consistent with the increase in AECO of 47% over the same period.

On a boe basis, the Company's realized price was 8% higher for the three months ended December 31, 2022, than the comparative period, due to the higher prices received for all its production. The Company's realized price per boe increased 45% for the year ended December 31, 2022, due to the much higher Canadian oil prices and the prices received for the Company's natural gas liquids, versus the comparative period.

Revenues

Oil and natural gas sales

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Oil	3,675	3,489	5	17,705	12,690	40
Natural gas liquids	1,973	2,354	(16)	10,291	7,478	38
Total liquids	5,648	5,843	(3)	27,996	20,168	39
Natural gas	2,924	3,075	(5)	13,180	10,196	29
Total sales	8,572	8,918	(4)	41,176	30,364	36
Per boe	51.30	47.39	8	56.95	39.26	45

Crude oil sales increased 5% in the three months ended December 31, 2022 as a decrease in oil production volumes of 9% was offset by an increase of 16% in realized oil prices. Crude oil sales for the year ended December 31, 2022 were 40% higher than the comparative period of 2021 as higher prices more than offset the lower production volumes.

Natural gas liquids revenue was lower by 16% in the three months ended December 31, 2022 as production decreases of 17% were offset by higher realized natural gas liquids prices of 1%. Natural gas liquids sales for the year ended December 31,2022 were 38% higher than the comparative period of 2021 due to price increases of 35% and higher production volumes of 2%.

Natural gas revenue decreased 5% in the quarter ended December 31, 2022 as lower production volumes of 9% were sold for a 5% higher realized natural gas price than in the comparative quarter of 2022. Natural gas sales for the year ended December 31, 2022 were 29% higher than the comparative period of 2021 as higher prices more than offset the lower production volumes.

The 4% decrease in oil and gas sales for the three months ended December 31, 2022 was due to an 11% decrease in production volumes sold in the quarter at a higher average price received per boe of 8% than the comparative quarter of 2021. The 36% increase in oil and gas sales for the year ended December 31, 2022 was due to a higher average price received per boe of 45% than the prior year offset by lower production volumes of 7% being sold in the year.

Revenues from the sale of oil, natural gas and natural gas liquids are normally collected on the 25th day of the month following production. Clearview receives over 96% of its monthly production revenue from its customers on this day throughout the year. The remaining 4% is collected within 30 days after the 25th day and represents joint operations, whereby the operator sells the production on Clearview's behalf and subsequently pays Clearview for its working interest share of the revenues.

Processing income

Clearview has a working interest in natural gas processing and compression facilities at its Carstairs, Garrington, Wilson Creek and Northville properties. The Company earns revenue from processing fees on third party production volumes utilizing these facilities, a fee for service arrangement.

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Processing income	120	128	(6)	516	472	9
Per boe	0.72	0.68	6	0.71	0.61	16

Processing income decreased slightly to $120 thousand for the three months ended December 31, 2022, a 6% decrease from the comparative quarter ended December 31, 2021. For the year ended December 31, 2022, processing income increased 9% versus the comparative period of 2021. Processing income increased due to increased third party volumes being processed at the Company's facilities and higher per unit fees being charged by the Company.

Risk management activities

Clearview enters into financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations, thereby protecting a portion of the revenues received from the sale of its production to its customers.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting. Rather, the Company records the fair value of its natural gas and crude oil financial contracts on the statement of financial position at each reporting period with the change in the fair value being classified as an unrealized gain or loss in earnings. The Company did not have any financial commodity price contracts outstanding at December 31, 2022.

For the year ended December 31, 2022, the Company recognized an unrealized gain of $1.1 million on its commodity contracts versus an unrealized loss of $0.7 million in the prior year ended December 31, 2021. In the three months ended December 31, 2022, Clearview recorded an unrealized gain on commodity contracts of $0.2 million as compared to an unrealized gain of $2.0 million in the three months ended December 31, 2021. The fair value of these contracts is based on the forward prices and market values provided by independent sources and represents the asset/liability that would have been received from/paid to the counterparties to settle the contracts at the end of the reporting period.

For the year ended December 31, 2022, the Company had a realized loss on commodity contracts of $5.0 million versus a realized loss in the prior year of $4.5 million. During the three months ended December 31, 2022, the Company recorded a realized loss of $37 thousand versus a realized loss of $1.6 million in the comparative quarter of 2021.

The Company entered into the following physical commodity price contracts outstanding since December 31, 2022.

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
March 1, 2023	July 31, 2023	Bbls/d	150	Edmonton Par - Physical	$104.76
April 1, 2023	October 31, 2023	GJ/d	2,000	AECO 5A - Physical	$2.13

Management monitors the forward price market for oil and natural gas, on an ongoing basis, and may contract additional production volumes as attractive pricing opportunities become available or if production increases from development or acquisitions.

Royalties

	Three months ended			Year ended		
Amount	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Crown – oil	495	410	21	2,655	1,034	157
Crown – natural gas liquids	520	658	(21)	2,865	2,013	42
Crown – natural gas	263	268	(2)	1,264	745	70
Gas cost allowance	(358)	(131)	173	(1,664)	(851)	96
Total Crown	920	1,205	(24)	5,120	2,941	74
Freehold	184	239	(23)	1,021	647	58
Gross over-riding	183	211	(13)	942	678	39
Total royalties	1,287	1,655	(22)	7,083	4,266	66
Per boe	7.70	8.79	(12)	9.80	5.52	78

The Company pays royalties to the provincial government ("Crown"), freeholders and gross over-riding royalty holders, which may be individuals or companies, and other oil and gas companies that own surface or mineral rights. Crown royalties are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to commodity price fluctuations and changes in production volumes on a well-by-well basis, subject to a minimum and maximum rate restriction prescribed by the Crown. The provincial government has also enacted various royalty incentive programs that are available for wells that meet certain criteria which can result in fluctuations in royalty rates. Freehold and gross overriding royalties are generally at a fixed rate. The majority of the Company's production is on Crown lands.

The Company reviews its entitlement to gas cost allowance at each reporting period. The timeframe for the royalty regulatory process, the complexity of the calculation and the uncertainty (particularly for non-operated properties from which the Company takes its revenue in kind) as to whether the Company will be eligible to actually receive the allowance are factors considered in determining the estimate and the amount to record for that period.

	Three months ended			Year ended		
Royalty rate	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Total Crown	10.7%	13.4%	(20)	12.5%	9.7%	29
Freehold	2.2%	2.7%	(19)	2.5%	2.2%	14
Gross over-riding	2.1%	2.4%	(13)	2.3%	2.2%	5
Total royalties	15.0%	18.5%	(19)	17.3%	14.1%	23

The overall royalty burden for the three months ended December 31, 2022 decreased by 19% to a rate of 15.0% versus 18.5% for the comparative period. Crown royalty rates were lower by 20% primarily due to lower production volumes more than offsetting higher prices and an increase in the gas cost allowance received by the Company. Freehold royalties and gross over-riding royalties decreased as well due to the sale of non-operated properties offset by higher realized prices.

The overall royalty burden for the year ended December 31, 2022 increased by 23% to a rate of 17.3% versus 14.1% for the comparative period. The increase was primarily a result of much higher realized sales prices for the Company's oil, natural gas and natural gas liquids production volumes despite a 96% increase in the gas cost allowance received by the Company.

Transportation expenses

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Transportation costs	328	291	13	1,255	1,307	(4)
Per boe	1.97	1.55	27	1.74	1.69	3

Transportation expenses include trucking costs for delivery of the Company's oil production and third-party pipeline tariffs to deliver natural gas production to the purchasers at the main market hubs. During 2022, the Company had 70% of its natural gas volumes under firm service transportation contracts with NGTL and operators of midstream facilities that process the Company's natural gas production.

Transportation expense increased 13% in the three months ended December 31, 2022. Transportation expense per boe for the three months ended December 31, 2022 increased 27% versus the comparative quarter of 2021, due to higher per unit charges for trucking.

For the year ended December 31, 2022, transportation costs were lower by 4% versus the comparative period of 2021. Transportation expense per boe for the year ended December 31, 2022 increased 3% versus the comparative year of 2021, due to lower production volumes of oil and natural gas.

Operating expenses

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Operating costs	4,182	3,167	32	15,319	12,217	25
Per boe	25.03	16.83	49	21.19	15.80	34

The Company continues to focus on reducing production costs given the volatility of oil and natural gas prices. However, some components of operating an oil and natural gas property are essentially fixed, (e.g. property taxes, lease rentals and insurance), resulting in higher operating costs per boe when production declines.

For the year ended December 31, 2022, the Company's operating costs per boe have increased 34%, representing a 25% increase in costs and a decrease in production volumes of 7% versus the comparative period of 2021. The increase in absolute operating costs is a reflection of upward price pressure on field services from increased demand due to rising commodity prices. In addition, there has been general inflation related to fuel and power costs, chemicals, lubricants and other consumables used in operations. The Company has also experienced higher fees from third party plant owners for the processing of its natural gas production and incurred higher repairs and maintenance, carbon taxes and manpower costs than in the comparative period of 2021.

Operating costs per boe for the three months ended December 31, 2022 were $25.03 per boe, higher by 49% than the comparative quarter of the prior year, at $16.83 per boe. This increase reflects a 32% increase in absolute operating costs, as noted above, compounded by a 11% decrease in production per day.

General and administrative expenses

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Gross costs	742	633	17	2,957	2,386	24
Overhead recoveries	(82)	(50)	64	(269)	(190)	42
Total G&A expenses	660	583	13	2,688	2,196	22
Per boe	3.94	3.10	27	3.72	2.84	31

General and administrative costs, net of recoveries, increased 13% and 22%, respectively, in the three months ended and year ended December 31, 2022, versus the comparative periods of 2021. The increase in costs is primarily due to increased personnel costs, the reinstatement of directors' fees, increased professional fees and higher consultant costs. The higher costs were compounded by lower production volumes for the quarter and the year resulting in a 27% increase in general and administrative expenses per boe for the three months ended December 31, 2022 versus the comparative quarter and 31% increase in 2022 as compared to the prior year.

Stock based compensation

Stock based compensation is the amortization over the vesting period of the fair value of stock options. The Company has granted options to acquire voting common shares to directors, officers, employees and consultants to provide an incentive and retention component of the compensation plan. The Board of Directors of the Company set the terms of the options at the time of grant. The fair value of all options granted is estimated at the time of the grant using the Black-Scholes option pricing model.

The first round of options granted in 2016 will expire 7 years from the date of grant and vest one third immediately and one third on each of the first and second anniversaries. Subsequent grants also expire 7 years from the date of grant but vest one third on each of the first, second and third anniversaries.

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Stock based compensation	51	50	2	208	203	2
Per boe	0.31	0.27	15	0.29	0.26	12

Stock based compensation expense for the three months and year ended December 31, 2022 was very similar to the comparative periods of 2021, respectively.

During the year ended December 31, 2022, 22,666 options were forfeited which related to employees who are no longer with the Company. Stock based compensation associated with the forfeited and unvested options in the amount of $23 thousand has been reversed and recorded in earnings.

During the year ended December 31, 2022, the Company granted 112,000 options with an exercise price of $2.06 per share, 26,737 restricted share units to officers and employees and 7,544 deferred share units to directors.

The fair value of the options at the date of measurement was determined based on a Black-Scholes calculation with the following inputs and outcomes:

	Year ended December 31, 2022	**Year ended December 31, 2021**
	Inputs	**Inputs**
Exercise price	**$2.06**	**$3.96**
Volatility	**100%**	**98%**
Expected option life	**6.5 years**	**6.5 years**
Dividend	**$nil**	**$nil**
Risk-free interest rate	**3.20%**	**1.37%**
Estimated cost per voting common share under option	**$2.04**	**$3.98**
Total estimated cost to be amortized over the vesting period	**$228**	**$199**

Depletion and depreciation

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Depletion	1,908	1,748	9	7,150	7,912	(10)
Depreciation	1	1	-	4	5	(20)
Total	1,909	1,749	9	7,154	7,917	(10)
Per boe – depletion	11.41	9.29	23	9.88	10.23	(3)
Per boe - depreciation	0.01	-	-	0.01	0.01	-
Total	11.42	9.29	23	9.89	10.24	(3)

The Company calculates depletion on property, plant and equipment using the unit-of-production method based on proved plus probable reserves. Depreciation is calculated based on the useful lives of office equipment and furniture.

The increase in depletion of 9% for the three months ended December 31, 2022 is primarily due to the reduction of proved plus probable reserves at December 31, 2022, dispositions of two non-operated properties and an 81% increase in capital spending in the quarter. Depletion for the year ended December 31, 2022 was 10% lower than the prior year. This decrease versus the comparative year reflects lower production volumes of 7% and a lower depletion rate per boe of 4% in 2022, due to positive reserve revisions at the end of 2021.

Impairment reversal

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Impairment reversal	-	(8,300)	(100)	-	(8,300)	(100)
Per boe	-	(44.11)	(100)	-	(10.73)	(100)

At December 31, 2022, Clearview identified indicators of impairment expense, primarily due to the losses incurred on the disposition of certain property, plant and equipment and the increase in both operating costs and capital costs due to inflationary pressure for oilfield services and consumables and the proceeds on disposition of property, plant and equipment. As a result, the Company completed an impairment test on two of its three CGU's and determined that no impairment was required for the Company's Central Alberta Oil CGU the Southern Alberta Oil. There were no indicators of impairment for the Central Alberta Gas CGU and no historic reversals of impairment left to record.

The estimated net recoverable amount was based on before-tax discount rates specific to the underlying reserve category as determined by the Company's independent third-party reserve evaluator at December 31, 2022 and risk profile of each CGU, net of decommissioning obligations. The discount rates used in the valuation were an average of 15% to 20%. The impairment tests, using the fair value less costs to sell method, indicated no impairment was required for the Company's CGU's.

The results of Clearview's impairment tests are sensitive to changes in quantities of reserves and future production, forward commodity pricing as forecast by three independent reservoir engineering companies, development costs, operating costs, royalty obligations, abandonment costs and discount rates. As such, any changes to these key estimates could decrease or increase the recoverable amounts of assets and result in additional impairment charges or in the reversal of previously recorded impairments charges.

The table below details the pricing used in estimating the recoverable amounts at December 31, 2022.

Year	WTI US/bbl	Edmonton Light Cdn/bbl	Bow River Medium Cdn/bbl	Propane Cdn/bbl	Butane Cdn/bbl	Pentane Cdn/bbl	AECO Spot Cdn/bbl
2023	80.33	103.76	77.46	39.80	53.88	106.22	4.23
2024	78.50	97.74	78.65	39.14	52.67	101.35	4.40
2025	76.95	95.27	78.42	39.74	51.42	98.94	4.21
2026	77.61	95.58	80.94	39.86	51.61	100.19	4.27
2027	79.16	97.07	82.78	40.47	52.39	101.74	4.34
2028	80.74	99.01	84.92	41.28	53.44	103.78	4.43
2029	82.36	100.99	86.65	42.11	54.51	105.85	4.51
2030	84.00	103.01	88.38	42.95	55.60	107.97	4.60
2031	85.69	105.07	90.15	43.81	56.71	110.13	4.69
2032	87.40	106.69	92.08	44.47	57.56	112.33	4.79
2033	89.15	108.83	93.92	45.35	58.71	114.58	4.88
2034	90.93	111.00	95.80	46.26	59.88	116.87	4.98
2035	92.75	113.22	97.71	47.19	61.08	119.21	5.08
2036	94.61	115.49	99.67	48.13	62.30	121.59	5.18
2037	96.50	117.80	101.66	49.09	63.55	124.02	5.29
2038+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

At December 31, 2021, Clearview identified indicators of impairment reversal, primarily due to the increase in commodity prices and significant positive technical revisions due to reduced decline rates and an optimization capital program undertaken during 2021. As a result, the Company completed an impairment reversal test on its three CGU's and determined that the net recoverable amount exceeded the carrying values for the Central Alberta Gas CGU and Central Alberta Oil CGU.

The estimated net recoverable amount was based on before-tax discount rates specific to the underlying reserve category as determined by the Company's independent third-party reserve evaluator at December 31, 2021 and risk profile of each CGU, net of decommissioning obligations. The discount rates used in the valuation was an average of 15% to 20%. The impairment reversal tests, using the fair value less costs to sell method, indicated the Central Alberta Gas CGU's recoverable amount was higher than its carrying value resulting in an impairment reversal of $5.8 million and that the Central Alberta Oil CGU's recoverable amount was higher than its carrying value resulting in an impairment reversal of $2.5 million, both recorded as a reversal of impairment in earnings, for a total reversal of impairment of $8.3 million.

The results of Clearview's impairment tests are sensitive to changes in quantities of reserves and future production, forward commodity pricing as forecast by three independent reservoir engineering companies, development costs, operating costs, royalty obligations, abandonment costs and discount rates. As such, any changes to these key estimates could decrease or increase the recoverable amounts of assets and result in additional impairment charges or in the reversal of previously recorded impairments charges.

The table below details the pricing used in estimating the recoverable amounts at December 31, 2021.

	WTI	Edmonton Light	Bow River Medium	Propane	Butane	Pentane	AECO Spot
Year	US/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl
2022	72.83	86.82	75.22	43.38	57.49	91.85	3.56
2023	68.78	80.73	69.92	35.92	50.17	85.53	3.21
2024	66.76	78.01	67.26	34.62	48.53	82.98	3.05
2025	68.09	79.57	68.60	35.31	49.50	84.63	3.11
2026	69.45	81.16	69.98	36.02	50.49	86.33	3.17
2027	70.84	82.78	71.37	36.74	51.50	88.05	3.23
2028	72.26	84.44	72.80	37.47	52.53	89.82	3.30
2029	73.70	86.13	74.25	38.22	53.58	91.61	3.36
2030	75.18	87.85	75.49	38.99	54.65	93.44	3.43
2031	76.68	89.61	77.00	39.77	55.74	95.32	3.50
2032	78.21	91.40	78.54	40.56	56.86	97.22	3.57
2033	79.78	93.23	80.11	41.37	57.99	99.17	3.64
2034	81.37	95.09	81.72	42.20	59.15	101.15	3.71
2035	83.00	96.99	83.35	43.05	60.34	103.17	3.79
2036	84.66	98.93	85.02	43.91	61.54	105.24	3.86
2037+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

Other costs (income)

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Bad debt provision (recovery)	-	(152)	(100)	-	(170)	(100)
Royalty holder settlement	-	(565)	(100)	-	(565)	(100)
Earned non-refundable deposit	-	-	-	-	(50)	(100)
Crown charges	-	387	(100)	-	387	(100)
Site rehabilitation program	(80)	(301)	(73)	(116)	(604)	(81)
Total	(80)	(631)	(87)	(116)	(1,002)	(88)
Per boe	(0.47)	(3.35)	(86)	(0.16)	(1.29)	(88)

During 2022, the Company has received $116,000 in grants from the Site Rehabilitation Program of the Government of Alberta. During the three months ended December 31, 2022, the Company received $80,000 in eligible government grants from the Site Rehabilitation Program of the Government of Alberta.

During the year ended December 31, 2021, the Company incurred $0.9 million in abandoning 29 gross (13.2 net) wells, represented by $0.3 million funded from cash flow from operations and $0.6 million from eligible government grants from the Site Rehabilitation Program of the Government of Alberta.

During 2021, the Company earned $50 thousand as a non-refundable deposit from a company interested in purchasing a property from Clearview. The acquirer was unable to complete the purchase and hence forfeited the deposit.

In 2021, Clearview collected on numerous receivables for which a provision had been recorded in the prior year while also reducing the provision recorded in the prior year for other receivables due to a much improved commodity price environment. At December 31, 2021, the Company recorded a provision of $20 thousand as an allowance for doubtful accounts.

In 2021, the Company agreed to a settlement of $0.6 million with a freehold royalty owner for the double payment of royalties for the period April 2012 to December 31, 2020.

In 2021, the Company incurred an expense of $0.4 million related to unpaid Crown charges billed by Crown for the first quarter of 2017 which had not been paid by the vendor, the receiver of a bankrupt company, related to oil and gas producing properties purchased by the Company in the first quarter of 2017.

Finance costs

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Interest - bank debt	39	208	(81)	393	946	(58)
Interest rate swaps	-	-	-	-	9	(100)
Interest - convertible debentures	31	31	-	95	126	(25)
Credit facility fees and costs	3	56	(95)	66	67	(1)
Cash finance costs (1)	73	295	(75)	554	1,148	(52)
Accretion expense	235	55	327	824	462	78
Total finance costs	308	350	(12)	1,378	1,610	(14)
Per boe – cash finance costs (1)	0.43	1.57	(73)	0.77	1.48	(48)
Per boe – accretion expense	1.41	0.29	386	1.14	0.60	90

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

Cash finance costs include interest on bank debt and lender fees, realized gains or losses on interest rate swaps and interest on convertible debentures.

Interest on bank debt in the three months ended and year ended December 31, 2022 decreased by 81% and 58%, respectively, versus the comparative periods. The decrease was due to lower outstanding bank debt being reduced by adjusted funds flow in excess of capital expenditures.

As of December 31, 2022, the Company would be subject to a rate of 8.95% (lender’s prime rate of 5.95% plus a credit spread of 3.0%) on prime based loans. The Company also has the option of borrowing using the lender’s guaranteed notes which are subject to a stamping fee plus the guaranteed note rate for 30, 60, 90 and 180 day terms.

The interest rates applicable to drawings under the lending agreement are based on a pricing margin grid and can change quarterly as a result of the ratio of all outstanding indebtedness to annualized quarterly funds flows as calculated in accordance with the agreement governing the facility ("Debt to Funds Flow"). Annualized quarterly funds flow is defined as earnings before depletion and depreciation, stock based compensation, accretion of decommissioning obligations and debenture discounts, unrealized gains or losses on commodity contracts, gains or losses on dispositions, non cash other costs (income) and deferred income taxes.

The interest rate on the convertible debentures is 10%, payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year.

The accretion of decommissioning obligations relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which at a minimum meets environmental standards. This accretion expense is estimated to extend over a term of the next 47 years due to the long-term nature of certain assets. Accretion expense increased 327% in the three months ended December 31, 2022 and 78% in the year ended December 31, 2022, as compared to the same periods of 2021. This increase in accretion expense was due to the decrease in expected abandonment dates based on the Company's proved plus probable reserves and an increase in the inflation rate.

Income taxes

The Company has concluded that it is not probable that the deferred income tax asset associated with temporary timing differences will be realized. As a result, it has not been recognized on the statement of financial position at December 31, 2022. Therefore, no deferred income tax expense or recovery has been recorded in earnings in the current period.

Clearview has no current income taxes payable and has estimated tax pools available against income of $136.9 million, including non-capital tax loss carry-forwards of $69.2 million which will expire over the years 2030 to 2041. The successor pools were acquired as part of oil and gas property acquisitions in March 31, 2017 and the acquisition of Bashaw Oil Corp. on April 16, 2018. The successor pools can be deducted to the extent of future profits attributable to the acquired properties. During the taxation years ended March 31, 2017 to December 31, 2022, Clearview has claimed $20.3 million against the successor pools.

The Company's tax pools as at December 31, 2022 are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	170	11,561	11,731
Canadian development expense (CDE)	30	6,218	10,977	17,195
Canadian oil and gas property expense (COGPE)	10	21,828	6,519	28,347
Foreign resource expenses	10	3,609	-	3,609
Undepreciated capital cost (UCC)	25	6,810	-	6,810
Share issue costs	20	3	-	3
Non-capital losses carry forward	100	69,186	-	69,186
Total tax pools		107,824	29,057	136,881

[1] The percentage rate shown is the maximum rate of deduction.
[2] The pools can be claimed to the extent of future profits attributable to the acquired properties related to the pools.

Adjusted funds flow

The following is a reconciliation of cash provided by operating activities to adjusted funds flow:

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Cash flow provided by operating activities	1,667	2,065	(19)	8,530	6,130	39
Add back (deduct)						
Decommissioning expenditures	269	162	66	667	341	96
Change in non-cash working capital	108	(430)	(125)	484	(898)	(154)
Adjusted funds flow (1)	2,044	1,797	14	9,681	5,573	74

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

Adjusted funds flow increased 14% for the three months ended December 31, 2022, primarily due to higher revenues, lower cash finance costs offset by higher realized losses on financial instruments, higher royalties and higher operating costs. For the quarter ended December 31, 2022, cash provided by operating activities was $1.7 million compared to $2.1 million for the quarter ended December 31, 2021.

Adjusted funds flow increased 74% for the year ended December 31, 2022, primarily due to higher revenues and lower cash finance costs offset by higher realized losses on financial instruments, higher royalties and higher operating costs. For the year ended December 31, 2022, cash provided by operating activities was $8.5 million compared to $6.1 million for the year ended December 31, 2021.

Net earnings (loss)

	Three months ended			Year ended		
	Dec. 31 2022	Dec. 31 2021	% Change	Dec. 31 2022	Dec. 31 2021	% Change
Net earnings (loss)	(6,406)	10,512	(161)	(2,549)	5,212	(149)
Per boe	(38.33)	55.86	(169)	(3.52)	6.73	(152)
Per share – basic	(0.55)	0.90	(161)	(0.22)	0.45	(149)
Per share – diluted	(0.55)	0.82	(167)	(0.22)	0.42	(152)

The Company generated a net loss of $6.4 million for the three months ended December 31, 2022 compared to net earnings of $10.5 million for the comparative quarter. The loss for the three months ended December 31, 2022 was primarily due to the loss of $6.5 million recognized on reclassifying property, plant & equipment to assets held for sale at fair value less costs to sell. The reclass related to a non-operated minor working interest property in its Central Alberta Oil CGU in the fourth quarter.

The Company had a net loss of $2.5 million for the year ended December 31, 2022, compared to net earnings of $5.2 million for the year ended December 31, 2021. The higher adjusted funds flow in the year ended December 31, 2022 was offset by an impairment expense on the reclassification to assets held for sale.

Netback analysis

	Three months ended			Year ended		
Barrel of oil equivalent ($/boe)	Dec. 31 2022	Dec. 31 2021	% Positive (Negative)	Dec. 31 2022	Dec. 31 2021	% Positive (Negative)
Realized sales price	51.30	47.39	8	56.95	39.26	45
Royalties	(7.70)	(8.79)	12	(9.80)	(5.52)	(78)
Processing income	0.72	0.68	6	0.71	0.61	(16)
Transportation	(1.97)	(1.55)	(27)	(1.74)	(1.69)	(3)
Operating	(25.03)	(16.83)	(49)	(21.19)	(15.80)	(34)
Operating netback (2)	17.32	20.90	(17)	24.93	16.86	48
Realized gain (loss) – financial instruments	(0.22)	(8.44)	97	(6.96)	(5.85)	(19)
General and administrative	(3.94)	(3.10)	(27)	(3.72)	(2.84)	(31)
Other (costs) income	-	1.75	(100)	-	0.51	(100)
Transaction costs	(0.49)	-	(100)	(0.11)	-	(100)
Cash finance costs (2)	(0.43)	(1.57)	73	(0.77)	(1.48)	48
Corporate netback (2)	12.24	9.54	28	13.37	7.20	86
Unrealized gain (loss) – financial instruments	0.95	10.46	(91)	1.54	(0.88)	275
Stock based compensation	(0.31)	(0.27)	(15)	(0.29)	(0.26)	(12)
Depletion and depreciation	(11.42)	(9.29)	(23)	(9.89)	(10.24)	3
Impairment reversal	-	44.11	(100)	-	10.73	(100)
E&E expense	(0.14)	-	(100)	(0.03)	-	(100)
Accretion	(1.41)	(0.29)	(386)	(1.14)	(0.60)	(90)
Other income	0.47	1.60	(71)	0.16	0.78	(79)
Gain on sale of E&E	-	-	-	1.69	-	100
Gain on A&D	0.08	-	100	0.02	-	100
Impairment on reclass to assets held for sale	(38.80)	-	(100)	(8.97)	-	- (100)
Net earnings (loss)	(38.34)	55.86	(169)	(3.54)	6.73	(153)

(1) % Positive (Negative) is expressed as being positive (better performance in the category) or negative (reduced performance in the category) in relation to operating netback, corporate netback and net earnings.

(2) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

The Company’s corporate netback for the quarter ended December 31, 2022 increased 28% to $12.24 per boe versus the comparative period. The increase is primarily due to the higher realized sales price per boe and lower royalties per boe offset by higher transportation and operating costs per boe in the current period versus the comparative period.

The Company’s corporate netback for the year ended December 31, 2022 increased 86% to $13.37 per boe versus the comparative period. The increase is primarily due to a higher realized sales price per boe offset by higher royalties, operating costs and higher realized losses on financial instruments per boe in the current year versus the comparative year.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Dec 31 2022	Sep 30 2022	Jun 30 2022	Mar 31 2022	Dec 31 2021	Sep 30 2021	Jun 30 2021	Mar 31 2021
Production								
Oil (bbl/d)	393	437	446	436	433	450	504	463
Natural gas liquids (bbl/d)	402	509	482	492	487	467	549	350
Natural gas (mcf/d)	6,125	6,360	6,528	6,965	6,755	6,942	7,233	7,715
Total (boe/d)	1,816	2,006	2,016	2,089	2,045	2,074	2,258	2,098
Financial								
Oil and natural gas sales	8,572	9,624	12,821	10,159	8,918	7,788	7,207	6,451
Net earnings (loss)	(6,406)	1,667	3,848	(1,657)	10,512	(1,101)	(2,527)	(1,672)
Per share – basic	(0.55)	0.14	0.33	(0.14)	0.90	(0.09)	(0.22)	(0.14)
Per share - diluted	(0.55)	0.13	0.30	(0.14)	0.82	(0.09)	(0.22)	(0.14)

In the fourth quarter of 2022, oil and natural gas sales decreased by $1.1 million as a result of lower prices for crude oil, natural gas, pentanes, propane and butanes and lower production volumes of oil and natural gas. The decrease in revenue was primarily offset by lower realized losses on risk management contracts of $36 thousand as compared to the $1.1 million in the third quarter of 2022. Net loss for the three months ended December 31, 2022 was $6.4 million (($0.55) per basic share), a decrease from the prior quarter, primarily due to an impairment expense to adjust to fair value less costs to sell on the reclassification to assets held for sale, of a non-operated minor working interest property in its Central Alberta Oil CGU, in the fourth quarter of 2022 of $6.5 million.

In the third quarter of 2022, oil and natural gas sales decreased by $3.2 million as a result of lower prices for crude oil, natural gas, pentanes, propane and butanes and lower production volumes of oil and natural gas. The decrease in revenue was primarily offset by lower realized losses on risk management contracts of $1.4 million as compared to the second quarter of 2022. The net earnings for the three months ended September 30, 2022 was $1.7 million ($0.14 per basic share), a decrease from the prior quarter, primarily due to the lower revenue and no gain on sales of assets of $1.2 million offset by the reduced realized losses on risk management contracts of $1.4 million.

In the second quarter of 2022, oil and natural gas sales increased to $12.8 million as a result of higher prices for crude oil, natural gas, pentanes and butanes and higher production volumes of oil. The increase in revenue of $2.7 million was primarily offset by higher royalties of $0.2 million and higher general and administrative costs of $0.4 million and an increase in realized losses on financial instruments of $1.2 million as compared to the first quarter of 2022. The net earnings for the three months ended June 30, 2022 was $3.8 million ($0.33 per basic share), an increase from the prior quarter, primarily due to higher revenue, a gain on sales of assets of $1.2 million and an unrealized gain on financial instruments of $1.4 million versus an unrealized loss on financial instruments in the first quarter of 2022 of $2.1 million.

In the first three months of 2022, oil and natural gas sales increased to $10.2 million as a result of higher prices for crude oil, natural gas, pentanes, propane and butanes and higher production volumes of primarily natural gas. The increase in revenue of $1.3 million was primarily offset by higher royalties of $0.2 million and higher operating costs of $0.5 million and a decrease of $0.3 million of other income in the quarter as compared to the fourth quarter of 2021. The net loss for the three months ended March 31, 2022 was $1.7 million ($0.14 per basic share), an increase from the prior quarter, primarily due to higher operating costs and a higher unrealized loss on financial instruments.

In the fourth quarter of 2021, oil and natural gas sales increased to $8.9 million as a result of higher prices for crude oil, pentanes, propane and butanes and higher production volumes of natural gas liquids. The increase in revenue of $1.1 million was primarily offset higher royalties of $0.7 million, an increase in the realized loss on financial instruments of $0.2 million but other income of $0.3 million as compared to the third quarter of 2021. Net earnings for the three months ended December 31, 2021 was $10.5 million ($0.90 per basic share), primarily as a result of an impairment reversal of $8.3 million.

In the third quarter of 2021, oil and natural gas sales increased to $7.8 million as a result of higher prices for crude oil, natural gas, pentanes, propane and butanes and higher production volumes of natural gas liquids. The increase in revenue of $0.6 million was primarily offset by an increase in the realized loss on financial instruments of $0.4 million but lower royalty costs of $0.3 million as compared to the second quarter of 2021. The net loss for the three months ended September 30, 2021 was $1.1 million ($0.09 per basic share).

In the second quarter of 2021, oil and natural gas sales increased to $7.2 million as a result of higher prices for crude oil, pentanes and butanes and higher production volumes of crude oil and natural gas liquids. The increase in revenue of $0.8 million was primarily offset by an increase in the realized loss on financial instruments of $0.5 million and higher royalty costs as compared to the first quarter of 2021. The net loss for the three months ended June 30, 2021 was $2.5 million ($0.22 per basic share).

In the first three months of 2021, oil and natural gas sales increased to $6.5 million as a result of higher prices for crude oil and natural gas liquids production and much higher prices for natural gas production as a result of extreme cold weather during February. The increase in revenue of $1.6 million was partially offset by an increase in the realized loss on financial instruments of $0.4 million and higher operating costs as compared to the fourth quarter of 2020. The net loss for the three months ended March 31, 2021 was $1.7 million ($0.14 per basic share). Net debt was reduced by $0.8 million during the first quarter of 2021 as the excess of adjusted funds flow over capital expenditures and abandonment and reclamation expenditures of $0.8 million was applied against bank debt and working capital.

LIQUIDITY AND CAPITAL RESOURCES

The Company has a planned capital program of $2.5 to $3.0 million for 2023, primarily of discretionary expenditures and no significant commitments. The Company's expected 2022 adjusted funds flow will provide the liquidity to execute this capital program.

The Company's liquidity was strengthened during 2022 as net debt was reduced by $9.7 million as Clearview's adjusted funds flow in 2022 in excess of net capital expenditures and decommissioning expenditures and proceeds from dispositions was used to repay outstanding bank debt.

As a result, net debt is $0.5 million at December 31, 2022, down from $10.2 million at December 31, 2021, with the components set out below.

As at	Dec. 31, 2022	Dec. 31, 2021
Cash and cash equivalents	242	1,183
Trade and other receivables	3,860	2,933
Prepaid expenses and deposits	770	703
Assets held for sale	2,891	-
Bank debt	-	(8,772)
Accounts payable and accrued liabilities	(4,939)	(4,622)
Liabilities related to assets held for sale	(1,430)	-
Decommissioning obligations	(711)	(410)
Convertible debentures	(1,222)	(1,208)
Net debt (1)	(539)	(10,193)

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See "Non-IFRS Measures" contained within this MD&A.

Balance sheet strength and flexibility remain a priority of the Company even through this much improved commodity price environment extending into 2023. The Company continues to consider funding alternatives, including an equity raise and/or non-core asset sales, building on the steps taken in prior years. Improved liquidity is a priority as the Company continues to evaluate strategic acquisitions. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

As of December 31, 2022, the Company has a revolving, operating demand loan ("Operating Facility") with an Alberta based financial institution ("Lender") with a facility limit of $10.0 million (December 31, 2021 - $15.0 million). At December 31, 2022, the Company had no outstanding bank debt versus $8.8 million at December 31, 2021.

During the three months ended June 30, 2022, the Company renewed its credit agreement with its lender, resulting in an upward revision to the Operating Facility, from $8.75 million to $10.0 million. In addition, the lender authorized the repayment of the $6.25 million term loan under the Business Credit Availability Program ("BCAP"), supported by the Export Development Canada ("EDC") Guarantee and the commensurate elimination of this credit facility ("EDC Facility"). The repayment was funded by cash held by the Company and borrowings under the Operating Facility.

The Operating Facility is reserve-based, revolving and payable on demand. As the available lending limits are based on the lender's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available credit that will be determined at each scheduled review. Drawings under the facility can be undertaken in the form of prime-based loans or guaranteed notes offered by the Lender.

The Operating Facility is secured by a general security agreement providing a security interest over all present and acquired property and a floating charge on all oil and natural gas assets.

The interest rates applicable to drawings under the facilities are based on a pricing margin grid and can change quarterly as a result of the ratio of all outstanding indebtedness to annualized quarterly funds flows as calculated in accordance with the agreement governing the facility ("Debt to Funds Flow"). Annualized quarterly funds flow is defined as earnings before depletion and depreciation, stock based compensation, accretion of decommissioning obligations and debenture discounts, unrealized gains or losses on commodity contracts, gains or losses on dispositions, non-cash other costs (income) and deferred income taxes.

Under the Operating Facility, prime-based loans are subject to an interest rate of lender prime plus a credit spread of 3.00% to 6.00%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0.

Guaranteed notes are subject to the Canadian Dollar Offered Rate ("CDOR") plus a stamping fee of 4.00% to 7.00%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0. Guaranteed notes may be undertaken for terms of 30, 60, 90 or 180 days.

The Company is subject to certain reporting and financial covenants, pursuant to its lending agreement. The agreement requires compliance with a working capital covenant whereby the Company must maintain a minimum working capital ratio of 1 to 1. For calculating compliance with this covenant, the amount drawn on the Operating Facility, classified as a current liability, and the fair value of financial instruments are excluded from working capital. Conversely, the amount of the undrawn portion of the Operating Facility is added to current assets. At December 31, 2022, the Company's working capital ratio for purposes of the lender's working capital covenant was 2.5:1 (2.2:1 at December 31, 2021). In addition, the Company and its lender have agreed to a covenant whereby the Company shall maintain a liability management rating ("LMR") of no less than 2.0. Clearview's LMR as at December 31, 2022 was 2.1.

At December 31, 2022, the Company had $nil of prime-based loans and $10 thousand in letters of credit outstanding on the Operating Facility.

The next credit review is scheduled to be completed by no later than June 30, 2023. In the event that the Operating Facility limit is reduced and the amount outstanding exceeds this facility limit, the Company shall have thirty days to repay any shortfall.

On December 31, 2022, the Company has $1.22 million of unsecured convertible debentures outstanding. The interest rate on the debenture is 10%, payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. During the term of the debenture, the debenture is convertible into common shares of the Company at the option of the holder based on a conversion price of $1.50 per common share.

The debentures have a term of five years and mature on November 30, 2025. The debentures may not be redeemed by the Company prior to December 1, 2022. During the remainder of the term, the Company may redeem the debentures over the term based on the following terms:

Year 3 – 105% of the principal amount plus accrued interest
Years 4 and 5 – 100% of the principal amount plus accrued interest

The subscribers to the debenture offering consisted of current shareholders of the Company, with the directors and officers of the Company participating in the offering.

The Company manages liquidity risk, the risk that the Company will not be able to meet its financial obligations as they become due, by monitoring cash flows from operating activities, reviewing actual capital expenditures against budget, managing maturity profiles of financial assets and liabilities and having an active commodity price risk management program.

CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's future minimum contractual obligations and commitments as of December 31, 2022.

	2023	2024	2025	2026	2027	Thereafter
Bank debt	-	-	-	-	-	-
Accounts payable and accrued liabilities	4,939	-	-	-	-	-
Decommissioning obligations	711	711	711	711	711	14,670
Convertible debentures	-	-	1,262	-	-	-
Total	5,650	711	1,973	711	711	14,670

OFF-BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements. The commodity contracts for oil and natural gas prices and interest rate swaps disclosed in the MD&A are recorded at fair value as Financial Instruments on the statements of financial position at each reporting period with gains and losses recognized in earnings.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares and an unlimited number of preferred shares, issuable in series. As of April 25, 2023, the Company has 11,725,855 voting common shares outstanding and 638,334 options to acquire voting common shares outstanding. All outstanding options have a 7-year life from the date of grant and vest as follows, based on respective exercise prices of between $1.25 and $5.00 per option.

For further details about the options refer to Note 10 to the financial statements as at and for the period ended December 31, 2022.

RELATED PARTY TRANSACTIONS

There were no related party transactions in the twelve months ended December 31, 2022.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's audited financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision to these estimates over time.

Management is often required to make judgments, assumptions and estimates in the application of International Financial Reporting Standards that may have a significant impact on the financial results of the Company. The Company's significant accounting policies are described in Note 3 to the audited financial statements for the periods ended December 31, 2022 and December 31, 2021. Certain estimates and judgments are described in Note 2 to the audited financial statements for the periods ended December 31, 2022 and December 31, 2021.

Current Environment

Early in 2022, energy prices strengthened to multi-year highs due to heightened uncertainty of global oil and natural gas supply after Russia's invasion of Ukraine in addition to limited production growth reflecting oil and gas producers' capital discipline. Declines in global oil prices during the second half of 2022 were caused by concern over future demand due to central bank actions to moderate inflation. The impact of these factors has been considered in management's estimates as at and for the period ended December 31, 2022.

Estimates and judgments made by management in the preparation of the financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

Environmental Reporting Regulations

Environmental reporting for private enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. Clearview continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

The following is a discussion of the accounting estimates that are critical in determining the Company’s financial results.

Property, plant and equipment

Oil and natural gas reserves - The Company’s proved and probable oil and natural gas reserves at the current and prior year end were evaluated and reported on by the Company’s independent qualified reserves evaluator. The estimation of reserves is a subjective process. Forecasts are based on geological and engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Proved and probable reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion on a unit of production basis. Significant changes to commodity price forecasts and/or reserve estimates could also result in impairment or an impairment recovery.

Depletion - The unit-of-production method of depletion is based on estimated proven and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on depletion expense.

Impairment - The impairment test uses forecast prices determined by the Company’s independent reserve evaluator adjusted for price differentials specific to the Company and considered reasonable and relevant to the Company’s products. The Company is also exposed to variability in operating and capital cost estimates and discount rates.

Decommissioning obligations

Decommissioning obligations are estimated for all wells and facilities in which the Company has an interest, regardless of whether reserves have been attributed to those assets by the Company’s independent reserves evaluator. The Company estimates the future retirement date and likely current abandonment and reclamation costs for each well and facility based on current regulatory requirements, the regulator’s estimates of such costs used to determine abandonment and reclamation costs and the Company’s own experience, including historical costs incurred for abandonment or reclamation. To estimate future retirement costs, the Company applied a 2.09% inflation factor to its estimate of current costs. The Company believes this inflation factor is reasonable over the long term and is consistent with rates used by others in the industry. The risk-free rate is used to discount decommissioning provisions to the current reporting date. Expected retirement dates are based on the productive life of the wells as determined by the independent qualified reserves evaluator and by regulatory requirements.

Stock based compensation

The Company's accounting policy for stock based compensation was applied to account for the options granted during the periods ended December 31, 2022 and December 31, 2021. The costs of stock based compensation are calculated by reference to the fair value of the options at the date on which they are granted, using the Black-Scholes option pricing model. The Company is not listed on any stock exchange so judgment is required to determine the exercise price and to estimate volatility for purposes of the Black-Scholes option pricing model. The exercise price has been the same price at which the Company issued voting common shares near the date of the option grant. If options are issued in the future and there have not been recent issues of the voting common shares to third parties, judgment will be necessary to estimate a fair value for the exercise price. The estimate of volatility is based on oil and natural gas producers listed on a Canadian stock exchange.

Deferred tax assets

At each reporting period the Company evaluates deferred income tax assets to make a determination of whether the assets are likely to be realized. Based on management's assessment that it is not probable that future taxable income will be available against which the temporary differences will be utilized, all deferred tax assets previously recognized were expensed in 2015 and 2016. If the Company were to record deferred income tax assets in the future or at such time as it is required to record a net deferred income tax liability, it will be required to determine substantially enacted income tax rates applicable to the future years. The Company estimates the accounting and tax values during the period over which temporary difference are likely to reverse and tax rates expected to be effective when the temporary differences reverse.

Financial instruments

The estimated fair values of derivative financial instruments resulting in financial assets and liabilities, by their very nature, require estimates. The Company ensures the price received for a portion of its oil and natural gas volumes through the use of financial derivatives and estimates the mark to market value at each reporting period by applying estimated forward prices to the contracted volumes.

Cash-generating units ("CGU")

The determination of which assets constitute a cash generating unit requires management to make judgments as to the assets to be grouped together. A cash-generating unit is defined to be the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. Because impairment testing is performed at the level of the cash-generating unit, rather than for individual assets, the composition of a CGU is an important judgement that may significantly impact the determination of recoverable amounts and the resulting impairment. The key estimates used in the determination of future cash flows from oil and natural gas assets include the following:

Reserves – The Company utilizes the reserves prepared by the Company's independent qualitied reserves evaluator. Assumptions that are valid at the time of the reserve estimation may change significantly when new information becomes available. Changes in forecast prices, production levels or results of future drilling may change the economic status of reserves and may result in reserves being revised.

Oil and natural gas prices – The Company utilizes the forecast prices provided by the Company's independent qualitied reserves evaluator. Commodity prices can fluctuate significantly within short periods of time for a variety of reasons including supply and demand fundamentals, access to facilities and pipelines, inventory levels, exchange rates, weather, and economic and geopolitical factors.

Operating costs, future development costs and estimates and timing of future decommissioning obligations – Estimates of future costs are used in the cash flow model, based on an analysis of actual costs incurred in recent years and then escalated for assumed future inflation. Actual results in the future may vary considerably from these estimates.

Discount rate – The Company estimates a range of discount rates for each of the six different categories of reserves (three categories for each of proved and probable reserves, being producing, developed but not producing and undeveloped). The estimated ranges of discount rates are those likely to be applied by an independent market participant and consideration of comparable asset transactions. Changes in the general economic environment could result in significant and rapid changes to discount rates being applied in the marketplace.

The determination of assets constituting a cash-generating unit requires judgment as to the assets to be grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.

Lease obligations

Lease obligations are estimated using the rate implicit in the lease, unless this rate is not readily determinable, in which case a discount rate equal to the Company's incremental borrowing rate is used.
This rate represents the rate that the Company would incur to obtain the funds necessary to purchase an asset of a similar value, with similar payment terms and security in a similar economic environment. Lease terms are based on assumptions regarding extension terms and renewal options that allow for operational flexibility and future market conditions.

Liquidity

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy, ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgement and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company. See further discussion related to liquidity in Note 14 of the audited financial statements for the year ended December 31, 2021.

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development, and acquisition of oil and gas reserves involves financial, operational and regulatory risks inherent in the oil and gas industry, several of which are beyond control of the Company, which may impact the Company's results.

The Company's revenues, profitability, future growth and the carrying value of its properties are substantially dependent on prevailing prices of oil and natural gas. The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to volatility in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company.

While the Board of Directors has the overall responsibility for the establishment and oversight of the Company's risk management framework, management has the responsibility to administer and monitor these risks. Refer to Note 15 of the audited financial statements for the year ended December 31, 2022 for additional analysis of these risks.

The Company's activities expose it to a variety of financial risks that arise from its exploration, development, production, and financing activities such as credit risk, liquidity risk and market risk. Presented below is information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout this MD&A and in the Company's audited financial statements. The Company employs risk management strategies and polices to ensure that any exposure to risk complies with the Company's business objectives and risk tolerance levels. The Company manages commodity price risks by focusing its acquisition program on areas that will generate attractive rates of return even at substantially lower commodity prices than those prices being received at the time of the acquisition. The Company uses derivative financial instruments to manage commodity price risk as described elsewhere in this MD&A.

The Company manages its working capital, net debt and the ratio of net debt to adjusted funds flow so as not to overextend the Company. Capital expenditures are limited to cash provided by operating activities, available lines of credit and proceeds from issuing shares when the Company believes that it is prudent.

Operational risks include exploration and development of economic oil and gas reserves, unsuccessful exploration and development drilling activity, competition from other producers, reservoir performance, safety and environmental concerns, access to and ability to retain cost effective contract services, escalating industry costs for contracted services and equipment, product marketing and hiring and retaining qualified employees.

The Company attempts to control operating risks by:

- maintaining a disciplined approach to implementation of the exploration and development program,
- monitoring operations and maintaining close communications with operators and joint interest partners,
- maintaining insurance commensurate with its level and scope of operations to protect against loss from destruction of assets, pollution, blowouts, or other losses.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, and local laws and regulations. Environmental legislation provides for, among other things, restrictions, and prohibitions on spills, releases, or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge.

Although the Company believes that it is compliant with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development, or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

The Company's operations are subject to risks normal in the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blowouts and fires, all of which could result in personal injuries, loss of life and damage to property of the Company and others. In accordance with customary industry practice, the Company is not fully insured against all these risks, nor are all such risks insurable, however management believes that adequate insurance has been obtained, where available. Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. The Company expects it will be able to fully comply with all regulatory requirements in this regard.

The Company is subject to a variety of regulatory risks that it does not control. Safety and environmental matters are monitored to ensure compliance and to ensure employees, contractors and the public are protected. Changes in government or regulatory policies for matters such as royalties, income taxes, surface rights, mineral rights, operational requirements or processes for regulatory approvals, may impact the Company’s operations, financial results and real or perceived risk to investors or creditors. These matters are largely beyond the Company’s control but are monitored and managed to the extent possible.

Widening concerns over climate change, fossil fuel consumption, green house gas emissions, and water and land use could lead governments to enact additional laws, regulations and costs or taxes that may be applicable to Clearview. Changes to environmental regulations related to climate change could impact the demand for, development of or quality of the Company’s petroleum products, or could require increased capital expenditures, operating expenses, asset retirement obligations and costs, which could result in increased costs which would reduce the profitability and competitiveness of Clearview if commodity prices do not rise commensurate with the increased costs. In addition, such regulatory changes could necessitate the Company to develop or adapt new technologies, possibly requiring significant investments of capital.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability 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 or evolve over time, has not yet been quantified.

Non-IFRS Measures

Throughout this MD&A and other materials disclosed by the Company, Clearview uses certain measures to analyze financial performance, financial position and cash flow. These non-IFRS 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-IFRS and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with IFRS as indicators of Clearview’s performance. Management believes that the presentation of these non-IFRS and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company’s ongoing operating performance, and the measures provide increased transparency and the ability to better analyze Clearview’s business performance.

Capital Management Measures

Adjusted Funds Flow

Adjusted funds flow represents cash provided by operating activities before changes in operating non-cash working capital and decommissioning expenditures. The Company considers this metric as a key measure that demonstrate the ability of the Company’s continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment, to repay debt and return capital to shareholders. Management believes that this measure provides an insightful assessment of the Company's operations on a continuing basis by eliminating the actual settlements of decommissioning obligations, the timing of which is discretionary. Adjusted funds flow should not be considered as an alternative to or more meaningful than cash provided by operating activities as determined in accordance with IFRS as an indicator of the Company’s performance. Clearview’s determination of adjusted funds flow may not be comparable to that reported by other companies. Clearview also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Net Debt

Clearview closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (current assets, excluding financial derivatives, less current liabilities, excluding financial derivatives, less convertible debentures) to assess financial strength, capacity to finance future development and to assist in assessing the liquidity of the Company.

Non-IFRS Measures and Ratios

Capital Expenditures

Capital expenditures equals additions to property, plant & equipment and additions to exploration & evaluation assets. Clearview considers capital expenditures to be a useful measure of adjusted funds flow used for capital reinvestment. The most directly comparable IFRS measure to capital expenditures is additions to property, plant & equipment and additions to exploration & evaluation assets.

Net Capital Expenditures

Net capital expenditures equals capital expenditures plus acquisitions of property, plant & equipment and less dispositions of property, plant & equipment. Clearview uses net capital expenditures to measure its total capital investment compared to the Company's annual capital budget expenditures. The most directly comparable IFRS measure to net capital expenditures is cash used in investing activities.

	Three months ended		Year ended	
	Dec. 31 2022	Dec. 31 2021	Dec. 31 2022	Dec. 31 2021
Cash used in investing activities	(325)	624	708	1,423
Changes in non-cash working capital	(148)	16	(193)	685
Net capital expenditures	(473)	640	515	2,108

Cash Finance Costs per boe

Cash finance costs per boe is calculated by dividing cash finance costs by total production volumes sold in the period. Management considers cash finance costs per boe an important measure to evaluate the Company's cost of debt financing relative to the Company's corporate netback per boe. The most directly comparable IFRS measure to cash financing costs is finance costs.

	Three months ended		Year ended	
	Dec. 31 2022	Dec. 31 2021	Dec. 31 2022	Dec. 31 2021
Finance costs	308	350	1,378	1,610
Accretion of decommissioning obligations and convertible debentures	(235)	(55)	(824)	(462)
Cash finance costs	73	295	554	1,148

Operating Netback per boe

Operating netback per boe is calculated by dividing operating netback by total production volumes sold in the period. Operating netback equals oil and natural gas sales plus processing income, less royalties, transportation expenses and operating expenses. Management considers operating netback per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Clearview's operating netback per boe can be seen in the section entitled "Netback Analysis" of this MD&A.

Corporate Netback per boe

Corporate netback per boe is calculated as operating netback less general and administrative expenses and cash finance costs, plus/(minus) realized gains (losses) on financial instruments, minus(plus) other costs (income), less transaction costs divided by total production volumes sold in the period. Management considers corporate netback per boe an important measure to assist management and investors in assessing Clearview's overall cash profitability. The calculation of

Clearview's corporate operating netback per boe can be seen in the section entitled "Netback Analysis" of this MD&A.

Supplementary Financial Measures

Adjusted funds flow per share is comprised of adjusted funds flow divided by the basic weighted average common shares.

Adjusted funds flow per diluted share is comprised of adjusted funds flow divided by the diluted weighted average common shares.

Realized sales price – oil is comprised of light crude oil commodity sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's oil production.

Realized sales price - ngl is comprised of natural gas liquids commodity sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's ngl production.

Realized sales price – natural gas is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's natural gas production.

Realized sales price – total is comprised of oil and natural gas sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's total production on a boe basis.

Forward-looking statements

The matters discussed in the MD&A include certain forward-looking statements. Forward-looking statements include, without limitation, any statement that may predict, forecast, indicate, or imply future results, performance, or achievements. Forward-looking statements may be identified, without limitation, by the use of such words as “anticipates”, “estimates”, “expects”, “intends”, “plans”, “predicts”, “projects”, “believes”, or words or phrases of similar meaning. In addition, any statement that may be made concerning future performance, strategies or prospects and possible future corporate action, is also a forward-looking statement. Forward-looking statements are based on current expectations and projections about future general economic, political and relevant market factors, such as interest rates, foreign exchange rates, equity and capital markets, and the general business environment, in each case assuming no changes to applicable tax or other laws or government regulation. Expectations and projections about future events are inherently subject to, among other things, risks and uncertainties, some of which may be unforeseeable. Accordingly, assumptions concerning future economic and other factors may prove to be incorrect at a future date. Forward-looking statements are not guarantees of future performance, and actual events could differ materially from those expressed or implied in any forward-looking statements made by the Company. Any number of important factors could contribute to these digressions, including, but not limited to, general economic, political and market factors in North America and internationally, interest and foreign exchange rates, global equity and capital markets, business competition, technological change, changes in government relations, unexpected judicial or regulatory proceedings and catastrophic events. The Company stresses that the above-mentioned list of important factors is not exhaustive. The Company urges all readers to consider these and other factors carefully before making any investment decisions. The Company urges all readers to avoid placing undue reliance on forward-looking statements. The Company disclaims any intention or obligation to update or revise these forward-looking statements as a result of new information, future events or otherwise, except as required under applicable securities laws.

Measures, conversions and acronyms

In this document, the abbreviations set forth below have the following meanings:

bbl	Barrel	mcf	Thousand cubic feet
mbbl	Thousand barrels	mmcf	Million cubic feet
bbl/d	Barrels per day	mcf/d	Thousand cubic feet per day
NGLs	Natural gas liquids	mmbtu	Million British Thermal Units
boe	Barrels of oil equivalent	gj	Gigajoule
boe/d	Barrels of oil equivalent per day	mboe	Thousand boe

Boe - Barrels of oil equivalent is determined on the basis of 1 boe to 6 mcf of natural gas and boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

WTI - West Texas Intermediate is the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade**.**
AECO – AECO is a natural gas storage facility located at Suffield, Alberta and the price of natural gas at this terminal is used as a benchmark for Canadian purposes.
API - an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To convert from	To	Multiply by
mcf	1,000 m^3 of gas	0.028
1,000 m^3 of gas	Mcf	35.493
Bbl	m^3 of oil	0.158
m^3 of oil	bbl	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
mcf	gj	0.95

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