Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

December 31, 2020

HIGHLIGHTS

In 2020, the Company was focused on and completed three strategic imperatives.

- Secured a workable credit agreement with its lender that provides the credit capacity and flexibility required for the current economic environment;

- Secured long-term funding through the Federal Government sponsored Export Development Canada ("EDC") Guarantee program in the amount of $6.25 million; and

- Raised $1.26 million in convertible debentures from the Company's very supportive shareholders to reduce the Company's outstanding bank debt.

During the year Clearview also concentrated on a series of significant operational measures during unprecedented economic and pandemic related circumstances that helped mitigate significant downward revisions to the Company's year end reserves.

- During the first quarter of 2020, the Company adopted austere operating practices to conserve cash in light of the severe drop in prices associated with the COVID-19 pandemic. As a result, over 2020 Clearview reduced its operating costs by $3.0 million, a decrease of 23%, its general and administrative costs by $0.7 million, a decrease of 30% and its capital program by $1.6 million, representing a decrease of 81%;

- Total production decreased 15% to average 2,055 barrels of oil equivalent per day ("boe/d") for the year ended December 31, 2020, due in combination to a significant production shut-in during the price collapse of 2020, minimal net capital expenditures of $0.4 million and significantly reduced repairs and maintenance spending;

- Clearview's realized sales price was $21.45 per barrel of oil equivalent ("boe") for the twelve months ended December 31, 2020, a decrease of 26%, compared to $29.08 per boe in the prior year. Natural gas prices continued to remain strong with the Company's realized price per mcf increasing 23% over the prior year; and

- Generated adjusted funds flow of $2.5 million in the year ended December 31, 2020 and cash flow from operations of $1.8 million as compared to $5.5 million and $5.0 million, respectively, in the comparative year.

A combination of all these factors has resulted in a substantially brighter financial picture for the company in 2021 with net debt reduced by $2.1 million from the prior year to $13.2 million on total credit capacity from its lenders of $21.25 million resulting in the removal of the going concern note from Clearview's financial statements.

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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, 2020 and December 31, 2019. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. 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 29, 2021.

Refer to page 30 for information about non-GAAP 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	5,300	87%	Yes
	Pembina	Liquids rich natural gas	1,236	80%	Yes
	Wilson Creek	Light oil and liquids rich natural gas	3,576	60%	Yes
	Windfall	Light oil	4,990	100.0%	Yes
	Niton	Light oil	1,351	96%	Yes
	Garrington	Light oil and liquids rich natural gas	1,469	94%	Yes
	Caribou	Light oil	558	63.3%	Yes
Other	Bantry	Medium oil	257	40.0%	No
	Carstairs (Unit)	Liquids rich natural gas	579	17.0%	No
	Lindale (Unit)	Light oil with associated natural gas and liquids	91	10.6%	No
	Miscellaneous	Various	89	Various	Mixed
Total			19,496		

[1] mboe of total proved plus probable reserves at December 31, 2020 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 structure;
- maintain an appropriate debt versus equity capital structure;
- build the Company's production base to fund the field capital program from internally generated funds;
- maintain strong lending values to support the Company's credit facility;
- maintain a current licensee liability rating of 2.0 or greater, providing the Company with the ability to transact on further acquisition opportunities; and
- evaluate non-core assets, for potential disposition, to fund the capital program.

SELECTED ANNUAL INFORMATION

	Three months ended		Periods ended		
	Dec. 31 2020	Dec. 31 2019	Dec. 31 2020	Dec. 31 2019	Dec. 31 2018
Oil and natural gas sales	4,870	6,512	16,133	25,687	16,273
Adjusted funds flow (1)	957	1,271	2,487	5,494	1,852
Per share – basic	0.08	0.11	0.21	0.48	0.18
Per share – diluted	0.08	0.11	0.21	0.48	0.18
Cash flow from operations	55	1,120	1,783	4,980	1,088
Per share – basic	-	0.10	0.15	0.43	0.11
Per share - diluted	-	0.10	0.15	0.43	0.11
Net earnings (loss)	16,891	(5,527)	(10,842)	(8,768)	(4,832)
Per share – basic	1.45	(0.48)	(0.93)	(0.76)	(0.48)
Per share – diluted	1.45	(0.48)	(0.93)	(0.76)	(0.48)
Total assets			70,498	80,038	80,752
Total long term liabilities			26,387	23,420	22,645
Net debt (1)			13,235	15,358	18,186
Total capital expenditures – net (2)	54	354	376	1,955	6,172

(1) See non-GAAP measures.
(2) Cash additions and acquisitions net of proceeds on dispositions

In the year ended December 31, 2020, revenues were lower than the comparative period of 2019 due to lower oil prices and lower production volumes from wells being shut-in for part of the second quarter. The shut-in production was primarily operated oil volumes and natural gas associated with the oil production due to low prices for oil and natural gas liquids stemming from the COVID-19 pandemic. The significant decrease in revenue of $9.6 million was partially offset by an increase in realized gains on risk management contracts of $1.1 million, lower royalties of $1.9 million, lower operating costs of $3.0 million, lower transportation costs of $0.2 million and lower general and administrative expenses of $ 0.7 million, resulting in adjusted funds flow being lower by $3.0 million versus the comparative year. Cash flow from operations was reduced due to the lower adjusted funds flow and a negative change in operating working capital of $0.6 million. The net loss for the year ended December 31, 2020 increased to $10.8 million, an increase of $2.1 million primarily due to lower adjusted funds flow by $3.0 million and an increase in impairment expense of $0.6 million. These reductions were partially offset by lower depletion expense of $2.0 million. Net debt was reduced by $2.1 million in 2020 as adjusted funds flow in excess of capital expenditures was applied against working capital and bank debt.

For the year ended December 31, 2019, the Company’s oil and natural gas sales increased to $25.7 million due to higher production from the acquisition of producing properties in the first quarter and increased total oil production for the Company from the new wells drilled in 2018. Adjusted funds flow was $5.5 million while cash flow from operations was $5.0 million for the year ended December 31, 2019. Long term liabilities increased in the year ended December 31, 2019 in connection with an acquisition of assets in the first quarter of 2019 and a decrease in interest rates negatively affecting the discounting of decommissioning obligations. Net debt was reduced over the twelve months ended December 31, 2019 as adjusted funds flow in excess of capital expenditures was applied against working capital and bank debt.

Acquisitions and dispositions

(a) Acquisition of assets

During the year ended December 31, 2020, the Company acquired partner working interests of jointly owned assets in 9 gross (3.5 net) wells in its Central Alberta Oil CGU. The partners paid Clearview $0.3 million to acquire their working interests, as the cost of decommissioning obligations assumed of $0.3 million exceeded the value of the assets.

In the prior year ended December 31, 2019, the Company acquired partner working interests of jointly owned assets in its Central Alberta Gas CGU for cash consideration of $16 thousand.

(b) Acquisition of Private Co. properties

On February 22, 2019, Clearview acquired producing oil and gas assets and undeveloped land from a private oil and gas producer ("Private Co") for cash consideration of $0.6 million and the issuance to Private Co of 1,361,542 voting common shares of Clearview issued from treasury. The operations of the acquired assets have been included in Clearview's results commencing on February 22, 2019.

The total consideration paid by Clearview was approximately $9.1 million based on a share price for Clearview of $6.25 per share. Transaction costs of $0.1 million were recorded in earnings. The acquisition of assets from Private Co has been accounted for as a business combination. The net assets have been allocated as follows:

Acquisition Date	February 22, 2019
Consideration	
Cash consideration	581
Share consideration (1,361,542 common shares)	8,509
Total consideration	9,090
Net assets at estimated fair value	
Working capital	87
Exploration and evaluation assets	182
Property, plant and equipment	10,764
Deferred income tax liabilities	(1,108)
Decommissioning obligations (see Note 9)	(835)
Net assets	9,090

The fair value of property, plant and equipment has been estimated based upon an independently prepared reserves evaluation. The fair value of decommissioning obligations at the time of the acquisition was estimated using a discount rate of 13%.

(c) Disposition of assets

In the year ended December 31, 2020, the Company closed the disposition of a non-operated minor working interest in a natural gas property in its Central Alberta Gas CGU for nil proceeds. No gain or loss was recorded in earnings related to the disposition. The disposition resulted in a reduction of $88 thousand in decommissioning obligations.

In the prior year ended December 31, 2019, the Company closed the disposition of a non-operated minor working interest in a natural gas property in its Central Alberta Gas CGU and the disposition of a royalty interest in 1,257 natural gas wells. Proceeds from the dispositions were $29 thousand, after closing adjustments, resulting in a gain on dispositions of $25 thousand, recorded in earnings. The dispositions included the reduction of $4 thousand in decommissioning obligations.

Capital expenditures

	Three months ended			Year ended		
	Dec. 31 2020	Dec.31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Land	-	7	(100)	3	7	(57)
Drilling, completions, equipping	11	303	(96)	311	931	(67)
Facilities	69	99	(30)	322	535	(40)
Other	(25)	(55)	(55)	2	1	100
Capital invested	55	354	(84)	638	1,474	(57)
Disposition of properties	-	-	-	-	(29)	(100)
Net capital invested	55	354	(84)	638	1,445	(56)
Acquisition of properties	(1)	-	(100)	(262)	510	(151)
Total capital expenditures	54	354	(85)	376	1,955	(81)

The Company spent less than one-third of its adjusted funds flow on capital expenditures in the twelve months ended December 31, 2020. The capital expenditures incurred were primarily for facility upgrades and minor optimizations.

Production

Production is summarized in the following table:

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Oil – bbl/d	487	621	(22)	480	684	(30)
Natural gas liquids – bbl/d	345	494	(30)	393	481	(18)
Total liquids – bbl/d	832	1,115	(25)	873	1,165	(25)
Natural gas – mcf/d	7,443	7,859	(5)	7,091	7,537	(6)
Total – boe/d	2,072	2,425	(15)	2,055	2,421	(15)

Production for the quarter ended December 31, 2020 decreased by 15% versus the respective comparative period. The decrease in production was partially due to lower oil production of 22% due to natural declines and having not drilled a well in the past two years. Natural gas liquids, generally associated with natural gas production, decreased 30% for the quarter ended December 31, 2020 versus the comparative period. The decrease was primarily due to a change in natural gas processing facility for a portion of the Company's natural gas production, effective in September 2020, which extracts fewer ethane volumes.

For the year ended December 31, 2020, overall production decreased by 15% due to the shut-in of volumes in the second quarter, reduced extraction of ethane volumes and natural declines as no new wells have been drilled in the past two years. In addition, minimal spending has been incurred on workovers or optimization projects in 2020. Instead, the Company's adjusted funds flow has been directed at the repayment of net debt.

Clearview's production portfolio for the year ended December 31, 2020 was weighted 23% to oil, 19% to natural gas liquids and 58% to natural gas. For the year ended December 31, 2019 the production mix was weighted 28% to oil, 20% to natural gas liquids and 52% to natural gas. The change in product mix over the current year has been influenced by the shut-in of operated oil production and associated natural gas in the second quarter of the year and the change in natural gas processing facility later in the year. A majority of the natural gas produced by the Company is either associated with light oil production or has significant natural gas liquids in the natural gas production stream.

Benchmark prices and economic parameters

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	42.67	56.96	(25)	39.39	57.03	(31)
Oil – Edmonton Par ($/bbl)	50.09	68.05	(26)	45.30	69.20	(35)
Differential – Light oil ($/bbl) (1)	5.45	7.13	(24)	7.34	6.47	13
NGLs - Pentane ($/bbl)	55.88	74.96	(25)	49.85	71.41	(30)
NGLs – Butane ($/bbl)	19.33	40.86	(53)	21.85	23.81	(8)
NGLs – Propane ($/bbl)	16.33	26.84	(39)	16.35	17.17	(5)
Natural gas – AECO ($/mcf)	2.56	2.47	4	2.22	1.75	26
Exchange rate – US$/Cdn$	0.768	0.758	1	0.746	0.754	(1)

(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 decreased from an average of US $56.96 per barrel in 2019 to US $42.67 per barrel in 2020 resulting in a 25% decrease. This significant decrease in WTI was a result of an over-supply of crude oil from Saudi Arabia and Russia, resulting in a price war early in 2020 and compounded by a drop in the demand for oil as a result of the COVID-19 pandemic and the shutdown of economies around the world. Canadian oil prices decreased by 26% in the three months ended December 31, 2020 compared to the same quarter in 2019 as the Canadian dollar strengthened by 1%, weakening Canadian prices, and the light oil differential narrowed by 24% over the same comparative quarter to offset a portion of the drop in WTI.

Benchmark oil prices for the year ended December 31 decreased from an average of US $57.03 per barrel in 2019 to only US $39.39 per barrel in 2020 resulting in a 31% decrease. Canadian oil prices decreased by 35% in the year ended December 31, 2020 compared to the same period in 2019 as the Canadian light oil differential or discount widened by 13% over the same comparative period on top of the drop in WTI.

Pentane prices decreased over the three months and year ended December 31, 2020 in a very similar manner to WTI pricing and Canadian light oil prices with decreases of 25% and 30%, respectively, versus the comparative periods of 2019.

Butane prices averaged $19.33 per barrel for the quarter ended December 31, 2020, a decrease of 53% from the same quarter of 2019. Butane prices averaged $21.85 per barrel for the year ended December 31, 2020, a decrease of 8% from the same period of 2019. The recovery in butane prices over the year of 2020 versus the same period in 2019 is largely due to the balancing of demand versus supply of butane in the Canadian market.

Propane prices averaged $16.33 per barrel for the quarter ended December 31, 2020, a decrease of 39% compared to the same quarter of 2019. Propane prices averaged $16.35 per barrel for the year ended December 31, 2020, a decrease of 5% from the same period of 2019. Similar to butane, the recovery in propane prices over 2020 versus 2019 is largely due to the removal of an oversupply of propane in the Canadian market.

AECO natural gas prices averaged $2.56 per mcf for the three months ended December 31, 2020, an increase of 4% as compared to the same quarter of 2019. For the year ended December 31, 2020, AECO natural gas prices are higher by 26% than the comparative period of 2019 as AECO pricing has been very strong throughout the year due to the low supply of natural gas in storage in Alberta and the ability to store excess natural gas production.

Realized sales prices

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Oil – $/bbl	45.41	64.03	(29)	41.50	64.69	(36)
NGLs – $/bbl	28.20	23.87	18	20.72	25.69	(19)
Natural gas – $/mcf	2.84	2.44	16	2.26	1.83	23
Total – $/boe	25.55	29.18	(12)	21.45	29.08	(26)

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, 2020, the Company's realized oil price was lower by 29% than the comparative quarter as a result of a 26% decrease in Edmonton Par benchmark pricing. The decrease in realized oil price of 36% for the year ended December 31, 2020 is consistent with the 35% decrease in the Edmonton Par benchmark pricing over the year.

Natural gas liquids prices were higher by 18% in the fourth quarter of the current year as compared to the same quarter of the prior year. This increase was primarily due to higher prices received for the Company's ethane, propane and butane production as a result of a new marketing agreement effective April 1, 2020.

The Company's realized price for natural gas was higher by 16% for the three months ended December 31, 2020. This compares to a 4% 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. A portion of the Company's natural gas production which is sold in Alberta received a higher price adjustment, non AECO based, in 2020 than in 2019 which had a positive effect on the Company's premium to AECO in 2020. For the year ended December 31, 2020, the realized natural gas price increased by 23%, compared to the prior year, consistent with the increase in AECO of 26% over the same period.

On a boe basis, the Company's realized price was 12% lower for the three months ended December 31, 2020 than the comparative period, due to the lower prices received for its oil production, partially offset by higher prices received for its natural gas and natural gas liquids production. The Company's realized price per boe decreased 26% for the year ended December 31, 2020 due to the decrease in realized oil and natural gas liquids prices, partially offset by higher natural gas prices.

Revenues

Oil and natural gas sales

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Oil	2,034	3,661	(44)	7,292	16,152	(55)
Natural gas liquids	895	1,085	(18)	2,983	4,503	(34)
Total liquids	2,929	4,746	(38)	10,275	20,655	(50)
Natural gas	1,941	1,766	10	5,858	5,032	16
Total sales	4,870	6,512	(25)	16,133	25,687	(37)
Per boe	25.55	29.18	(12)	21.45	29.08	(26)

Crude oil sales decreased 44% in the three months ended December 31, 2020 as a decrease in oil production volumes of 22% was compounded by a decrease of 29% in realized oil prices.

Natural gas liquids revenues were lower by 18% in the quarter ended December 31, 2020 as production decreases of 30% were offset by higher realized natural gas liquids prices by 18%.

Natural gas revenue increased 10% in the quarter ended December 31, 2020 as lower production volumes of 5% were sold for a 16% higher realized natural gas price than in the comparative quarter.

The 25% decrease in oil and gas sales for the three months ended December 31, 2020 is due to both lower production volumes being sold in the quarter by 15% and an average lower price received per boe by 12% than the comparative quarter. The 37% decrease in oil and gas sales for the year ended December 31, 2020 is due to both lower production volumes being sold in the period by 15% and an average lower price received per boe of 26% than the prior 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 Caroline, 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 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Processing income	119	195	(39)	518	694	(25)
Per boe	0.62	0.87	(29)	0.69	0.79	(13)

Processing income decreased to $119 thousand for the three months ended December 31, 2020, a 39% decrease from the comparative quarter ended December 31, 2019. For the year ended December 31, 2020, processing income decreased 25% versus the comparative period of 2019. Processing income decreased due to lower third party volumes being processed at the Company's facilities.

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 had the following financial commodity price contracts outstanding at December 31, 2020.

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
January 1, 2021	March 31, 2021	GJ/day	1,000	AECO 5A – Financial	$2.91
January 1, 2021	March 31, 2021	GJ/day	1,000	AECO 5A – Financial	$2.79
January 1, 2021	October 31, 2021	GJ/day	1,000	AECO 5A – Financial	$2.43
January 1, 2021	December 31, 2021	GJ/day	1,000	AECO 5A – Financial	$2.10
April 1, 2021	October 31, 2021	GJ/day	2,000	AECO 5A - Financial	$1.86
January 1, 2021	October 31, 2021	Bbls/day	100	Edmonton Par - Financial	$49.45
January 1, 2021	October 31, 2021	Bbls/day	100	Edmonton Par - Financial	$52.05
January 1, 2021	December 31, 2021	Bbls/day	150	US WTI – Call option	$65.00**

** The Company sold a call option for 2021 on 150 barrels per day at US $65.00 per barrel and transferred the value for selling the call into a financial hedge for US $58.05 per barrel in 2020.

The fair value of the financial commodity and interest rate contracts outstanding as at December 31, 2020 is estimated to be a liability of $0.4 million. At December 31, 2019 the fair value of the financial contracts outstanding was a liability of $0.2 million. The fair value of these contracts is based on the forward prices and market values provided by independent sources and represents the asset that would have been received from the counterparties to settle the contracts at the end of the reporting period. Due to the volatility of commodity prices, interest rates and foreign exchange rates, actual amounts may differ from these estimates.

For the year ended December 31, 2020, the Company recognized an unrealized loss of $0.2 million on its outstanding commodity contracts versus an unrealized loss of $0.3 million in the prior year ended December 31, 2019. In the three months ended December 31, 2020, Clearview recorded an unrealized gain on commodity contracts of $0.3 million as compared to an unrealized loss of $0.3 million in the three months ended December 31, 2019. The unrealized loss in the three months and fiscal year ended December 31, 2020 is the difference between the fair values of the commodity contracts at December 31, 2020 and the fair values of outstanding commodity contracts at the respective prior reporting periods.

For the year ended December 31, 2020, the Company had a realized gain on commodity contracts of $1.2 million versus a realized gain in the prior year of $49 thousand. During the three months ended December 31, 2020, the Company recorded a realized loss of $79 thousand versus a realized loss of $78 thousand in the comparative quarter.

The Company has executed additional commodity price contracts for its oil production, subsequent to December 31, 2020, as follows:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
February 1, 2021	October 31, 2021	Bbls/day	100	Edmonton Par - Financial	$58.45

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.

The Company has a variable rate credit facility outstanding and consequently the Company is exposed to fluctuations in interest rates. The Company had the following financial interest rate swaps outstanding as of December 31, 2020. The realized gains or losses on the interest rate swaps are recorded in finance costs on the statement of operations.

Commencement Date	Expiry Date	Notional Amount	Underlying Commodity	Fixed Rate
January 1, 2021	March 31, 2021	$3,000,000	CDOR - Financial	1.41%
January 1, 2021	March 31, 2021	$3,000,000	CDOR - Financial	1.20%

Royalties

	Three months ended			Year ended		
Amount	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Crown – oil	64	272	(76)	303	1,184	(74)
Crown – natural gas liquids	236	294	(20)	824	1,170	(30)
Crown – natural gas	161	73	121	432	257	68
Gas cost allowance	(398)	(327)	22	(1,184)	(1,426)	(17)
Total Crown	63	312	(80)	375	1,185	(68)
Freehold	(63)	194	(132)	154	796	(81)
Gross over-riding	98	132	(26)	355	827	(57)
Total royalties	98	638	(85)	884	2,808	(69)
Per boe	0.51	2.86	(82)	1.18	3.18	(63)

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 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 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Total Crown	1.3%	4.8%	(73)	2.3%	4.6%	(50)
Freehold	(1.3)%	3.0%	(143)	1.0%	3.1%	(68)
Gross over-riding	2.0%	2.0%	-	2.2%	3.2%	(31)
Total royalties	2.0%	9.8%	(80)	5.5%	10.9%	(50)

The overall royalty burden for the three months ended December 31, 2020 decreased by 80% to a rate of 2.0% versus 9.8% for the comparative period. Crown royalty rates were lower by 73% due to low prices received for the Company's oil production. Crown royalties on natural gas and natural gas liquids production were largely offset by gas cost allowance. Freehold royalties decreased due to lower realized prices and a $0.1 million royalty adjustment received. Gross over-riding royalties decreased due to lower realized prices.

The overall royalty burden for the year ended December 31, 2020 decreased by 50% to a rate of 5.5% versus 10.9% for the comparative period. The decrease was a result of lower oil and natural gas liquids prices and reduced production volumes.

Transportation expenses

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Transportation costs	297	342	(13)	1,178	1,428	(18)
Per boe	1.56	1.53	2	1.57	1.62	(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 2020, the Company had 76% 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 decreased 13% in the three months ended December 31, 2020 which is consistent with the decrease in production volumes of 15% on a comparative quarter basis. Transportation expense per boe for the three months ended December 31, 2020 remained reasonably consistent with the comparative quarter of 2019.

For the year ended December 31, 2020, transportation costs were lower by 18%. The decrease is a combination of lower production volumes of 15% and the negotiation of lower cost of services with transportation companies during the price collapse period of the second quarter of 2020.

Operating expenses

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Operating costs	2,328	3,555	(35)	10,113	13,146	(23)
Per boe	12.21	15.93	(23)	13.44	14.88	(10)

The Company continues to focus on reducing production costs given the volatility of oil and natural gas prices. However, components of operating an oil and natural gas property are essentially fixed, e.g. property taxes, lease rentals and insurance.

Operating costs per boe for the three months ended December 31, 2020 were $12.21 per boe, lower by 23% than the comparative quarter of the prior year, at $15.93 per boe. This decrease reflects a 35% decrease in costs as austere operating measures were undertaken related to field operations in light of low oil prices and the shut-in of production volumes in the second quarter of 2020. These lower costs were partially offset by a 15% decrease in production per day resulting in an overall reduction in operating costs per boe of 23%.

Operating costs for the year ended December 31, 2020 were lower by 23% versus the comparative year, primarily due to austere operating measures undertaken beginning in the second quarter and maintained throughout the year by the Company which were partially offset by lower production volumes of 15% over the same comparative period. As a result, operating costs per boe were lower by 10% compared to the prior year.

General and administrative expenses

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Gross costs	486	594	(18)	1,833	2,535	(28)
Overhead recoveries	(45)	(67)	(33)	(222)	(249)	(11)
Total G&A expenses	441	527	(16)	1,611	2,286	(30)
Per boe	2.31	2.36	(2)	2.14	2.59	(17)

General and administrative costs, net of recoveries, decreased 16% in the three months ended December 31, 2020 versus the comparative period, primarily as a result of a decrease in personnel costs associated with reduced salaries, directors' fees and consultant costs. For the year ended December 31, 2020, general and administrative costs, net of recoveries, were lower by 30% due to cost cutting initiatives. These initiatives primarily included the elimination of contract office positions, the elimination of directors' fees, reduced salaries for staff and management initiated during the second quarter and the receipt of $25 thousand in the fourth quarter, $0.2 million for the year ended December 31, 2020, under the federal Canada Emergency Wage Subsidy program.

These and other cost cutting measures undertaken by the Company resulted in a reduction in the general and administrative expenses per boe of 17% for the year ended December 31, 2020, despite a 15% reduction in production volumes for the 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 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 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Stock based compensation	123	145	(15)	378	834	(55)
Per boe	0.65	0.65	-	0.50	0.94	(47)

Stock based compensation expense for the three months ended December 31, 2020 and year ended December 31, 2020 was lower by 15% and 55%, respectively, versus the comparative periods. The decrease in expense is primarily due to graded vesting which records more expense in the earlier years after granting for options granted to a director and numerous employees in the second quarter of 2018. During the year ended December 31, 2020, the Company cancelled 804,000 options and granted 321,600 options to directors, officers and employees at an exercise price of $1.25 per share under option.

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, 2020
	Inputs
Exercise price	**$1.25**
Volatility	**83%**
Expected option life	**6.5 years**
Dividend	**$nil**
Risk-free interest rate	**0.51%**
Estimated cost per voting common share under option	**$1.11**
Total estimated cost to be amortized over the vesting period	**$357**

Depletion, depreciation and impairment

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Depletion	2,057	2,440	(16)	8,061	10,034	(20)
Depreciation	1	1	-	6	7	(14)
Impairment	(18,000)	3,750	(580)	4,300	3,750	15
Total	(15,942)	6,191	(358)	12,367	13,791	(10)
Per boe – depletion	10.79	10.93	(1)	10.72	11.36	(6)
Per boe - depreciation	-	0.01	(100)	0.01	0.01	-
Per boe - impairment	(94.42)	16.80	(662)	5.72	4.24	35
Total	(83.63)	27.74	(401)	16.45	15.61	5

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 decrease in depletion for the three months ended December 31, 2020 is primarily due to lower production volumes and the impairment expense taken in the first quarter of 2020. Production decreased 15% and the depletion rate per boe decreased by 1% resulting in an overall reduction in depletion expense of 16% versus the comparative quarter of 2019. Depletion for the year ended December 31, 2020 was 20% lower than the prior year. This decrease reflects lower production volumes of 15% and a lower depletion rate per boe of 6% in 2020 than the comparative year.

At December 31, 2020, 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 reduced operating costs, since the last impairment test performed on March 31, 2020. As a result, the Company completed an impairment reversal test on two of 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, 2020 and risk profile of each CGU, net of decommissioning obligations. The discount rate used in the valuation was an average of 15%. 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 $10.9 million and that the Central Alberta Oil CGU's recoverable amount was higher than its carrying value resulting in an impairment reversal of $7.7 million, both recorded as a reversal of impairment in earnings, for a total reversal of impairment of $18.6 million.

At December 31, 2020, Clearview identified indicators of impairment, primarily due to continued production declines with no capital spending directed to its Southern Alberta Oil CGU. As a result, the Company completed an impairment test on the CGU and determined that the net carrying amount exceeded the net recoverable amount for the Southern 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, 2020 and risk profile of the CGU, net of decommissioning obligations. The discount rate used in the valuation was an average of 15%. The impairment test, using the fair value less costs to sell method, indicated the Southern Alberta Oil CGU's recoverable amount was lower than its carrying value resulting in an impairment of $0.6 million being recorded in earnings.

The following table details the forward pricing used in estimating the recoverable amount of each CGU at December 31, 2020.

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
2021	47.17	55.76	45.36	18.18	26.36	59.24	2.78
2022	50.17	59.89	48.96	21.91	32.85	63.19	2.70
2023	53.17	63.48	52.91	24.57	39.20	67.34	2.61
2024	54.97	65.76	54.95	25.47	40.65	69.77	2.65
2025	56.07	67.13	56.05	26.00	41.50	71.18	2.70
2026	57.19	68.53	57.16	26.54	42.36	72.61	2.76
2027	58.34	69.95	58.30	27.09	43.24	74.07	2.81
2028	59.50	71.40	59.47	27.65	44.14	75.56	2.87
2029	60.69	72.88	60.66	28.23	45.06	77.08	2.92
2030	61.91	74.34	61.87	28.79	45.96	78.62	2.98
2031	63.15	75.83	63.10	29.37	46.88	80.2	3.04
2032	64.41	77.34	64.37	29.95	47.82	81.80	3.10
2033	65.70	78.89	65.65	30.55	48.77	83.44	3.16
2034	67.01	80.47	66.97	31.16	49.75	85.10	3.23
2035	68.35	82.08	68.31	31.79	50.74	86.81	3.29
2036+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

At March 31, 2020, due to the decline in current and forward oil, natural gas and natural gas liquids prices, Clearview determined there were indicators of impairment present affecting all three of its CGU's. As a result, the Company completed an impairment test on its three CGU's, Central Alberta Gas, Central Alberta Oil and Southern Alberta Oil at March 31, 2020 based on fair value less cost to sell to calculate the estimated recoverable amount of each CGU. The estimated recoverable amount was based on before-tax discount rates specific to the underlying reserve category as determined by the Company's independent third party evaluator as of December 31, 2019 and updated by the Company to March 31, 2020 and risk profile of each CGU, net of decommissioning obligations. The discount rates used in the valuation ranged from 10 to 20 percent. The tests indicated an impairment in all three CGU's. For the Central Alberta Gas CGU, the carrying value exceeded the recoverable amount by $13.8 million, the Central Alberta Oil CGU carrying value exceeded the recoverable amount by $7.0 million and the Southern Alberta Oil CGU carrying value exceeded the recoverable amount by $1.5 million. This resulted in a total impairment of $22.3 million.

The following table details the forward pricing used in estimating the recoverable amount of each CGU at March 31, 2020.

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/gj
2020	29.17	29.22	19.55	10.04	18.27	34.35	1.74
2021	40.45	46.85	35.07	17.08	29.70	50.72	2.20
2022	49.17	59.27	46.87	23.55	37.87	62.80	2.38
2023	53.28	65.02	51.81	26.03	41.80	68.49	2.45
2024	55.66	68.43	54.85	27.57	44.14	71.73	2.53
2025	56.87	69.81	56.29	28.19	45.02	73.16	2.60
2026	58.01	71.24	57.54	28.83	45.95	74.66	2.66
2027	59.17	72.70	58.82	29.49	46.89	76.19	2.72
2028	60.35	74.19	60.12	30.17	47.86	77.75	2.79
2029	61.56	75.71	61.44	30.85	48.84	79.34	2.85
2030	62.79	77.22	62.67	31.47	49.81	80.93	2.91
2031	64.05	78.77	63.92	32.10	50.81	82.55	2.97
2032	65.33	80.34	65.20	32.74	51.83	84.20	3.03
2033	66.63	81.95	66.50	33.40	52.86	85.88	3.09
2034	67.97	83.59	67.83	34.07	53.92	87.60	3.15
2035+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

As a result of the impairment tests completed during 2020, the Company recognized a net impairment expense of $4.3 million.

At December 31, 2019, Clearview identified indicators of impairment, primarily due to the volatility of Canadian natural gas prices, forecast commodity prices having declined from the previous year, primarily natural gas and the Company's change in development plans for the Southern Alberta Oil CGU. Clearview performed an impairment test on its Central Alberta Gas and Southern Alberta Oil CGU's at December 31, 2019 based on fair value less cost to sell to calculate the estimated recoverable amount of each CGU. The estimated recoverable amount was based on before-tax discount rates specific to the underlying reserve category and risk profile of each CGU, net of decommissioning obligations. The discount rates used in the valuation ranged from 15 to 25 percent. The impairment test indicated the Company's Central Alberta Gas CGU's recoverable amount was less than its carrying value resulting in an impairment of $3.75 million charged to earnings.

The following table details the forward pricing used in estimating the recoverable amount of each CGU at December 31, 2019.

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
2020	61.00	72.64	58.43	26.36	42.10	76.83	2.04
2021	63.75	76.06	63.00	29.80	47.03	79.82	2.32
2022	66.18	78.35	64.99	32.94	50.66	82.30	2.62
2023	67.91	80.71	66.91	34.00	52.21	84.72	2.71
2024	69.48	82.64	68.65	34.88	53.48	86.71	2.81
2025	71.07	84.60	70.41	35.78	54.77	88.73	2.89
2026	72.68	86.57	72.20	36.69	56.07	90.77	2.96
2027	74.24	88.49	73.91	37.57	57.32	92.76	3.03
2028	75.73	90.31	75.53	38.41	58.50	94.65	3.09
2029	77.24	92.17	77.18	39.26	59.71	96.57	3.16
2030	78.79	94.01	78.72	40.04	60.90	98.50	3.23
2031	80.36	95.89	80.29	40.85	62.12	100.47	3.29
2032	81.97	97.81	81.90	41.66	63.36	102.48	3.36
2033	83.61	99.76	83.54	42.50	64.63	104.53	3.43
2034	85.28	101.76	85.21	43.35	65.92	106.62	3.49
2035+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

Other costs

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Bad debt provision	256	-	100	256	-	100
Site rehabilitation program	(51)	-	100	(51)	-	100
Total	205	-	100	205	-	100
Per boe	1.07	-	100	0.27	-	100

Other costs includes a provision for uncollectible receivables from its joint interest partners due to the challenging environment experienced by the industry in 2020. In 2020, the Company received $51 thousand, representing its working interest share, of $92 thousand of grant funds for abandonment and reclamation operations undertaken on 5 gross (2.9 net) wells.

Transaction costs

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Transaction costs	-	7	(100)	-	118	(100)
Per boe	-	0.03	(100)	-	0.13	(100)

Transactions costs for the year ended December 31, 2020 were nil versus $0.1 million in the comparative year for costs associated with the acquisition of assets from a private company which closed on February 22, 2019.

Finance costs

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Interest - bank debt	243	264	(8)	963	1,074	(10)
Interest rate swaps	12	-	100	36	-	100
Interest - convertible debentures	11	-	100	11	-	100
Credit facility fees and costs	318	25	1,172	360	76	374
Cash finance costs	584	289	102	1,370	1,150	19
Accretion expense (1)	89	170	(48)	287	457	(37)
Total finance costs	673	459	47	1,657	1,607	3
Per boe – cash finance costs	3.06	1.29	137	1.82	1.30	40
Per boe – accretion expense	0.47	0.76	(38)	0.38	0.52	(27)

(1) Accretion is a non-cash finance cost associated with the Company's decommissioning obligation and convertible debentures.

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

Interest on bank debt in the three months ended and year ended December 31, 2020 decreased by 8% and 10%, respectively, versus the comparative period. The decrease was due to the lower bank prime lending rate and Canadian Dollar Offered Rate ("CDOR") during most of the year and outstanding bank debt being reduced by adjusted funds flow in excess of capital expenditures. These factors were offset by a slightly higher credit spread pursuant to the Company's lending agreement.

Prior to the renewed credit facilities, the Company incurred an increase in the credit spread during the year of 3.0% to 4.0% in accordance with the pricing grid of the lending agreement. As a result of a decrease in the lender's prime rate over the year, the overall rate decreased from 6.95% at the beginning of the year to 6.45% at the end of November 2020 on prime-based loans. Effective December 1, 2020, the Company is paying 8.70% (lender's prime rate of 2.45% plus a credit spread of 6.25%) 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. Prior to the renewed credit facilities, the Company incurred a stamping fee of 4.0% to 5.0% in accordance with the pricing grid of the lending agreement. As a result of a decrease in the lender's prime rate over the year, the overall rate decreased from 6.45% at the beginning of the year to 5.50% at the end of November 2020 on guaranteed notes. Effective December 1, 2020, the Company is paying 7.75% (CDOR of 0.50% plus a stamping fee of 7.25%) on guaranteed notes.

In addition, the Company paid its lender a standby fee on the difference between the credit facility of $18.5 million and the combined prime-based loans and guaranteed notes borrowings for eleven months of the year. Beginning December 1, 2020, the standby fee is calculated based on the combined credit facilities limit of $21.25 million.

In the fourth quarter of 2020, the Company's lender completed its credit review. Credit facility fees and costs include legal fees associated with the review, renewal fees for the credit facilities, a consultant fee related to the EDC guarantee and an annual 1.8% fee for the guaranteed facility.

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 decreased in the three months and year ended December 31, 2020 due to the extension of the average abandonment date.

Income taxes

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Deferred income tax recovery	16	-	100	16	1,108	(99)
Per boe	0.08	-	100	0.02	1.25	(98)

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, 2020. Therefore, no deferred income tax expense or recovery has been recorded in earnings in the current period. The deferred tax recovery of $16 thousand for the year ended December 31, 2020 represents the deferred income tax effect of the equity component of the convertible debentures.

Clearview has no current income taxes payable and has estimated tax pools available against income of $148.5 million, including non-capital tax loss carry-forwards of $71.2 million which will expire over the years 2024 to 2039. 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 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, 2020, Clearview has claimed $14.4 million against the successor pools.

The Company’s tax pools as at December 31, 2020 are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	170	14,257	14,427
Canadian development expense (CDE)	30	5,034	12,636	17,670
Canadian oil and gas property expense (COGPE)	10	27,057	7,243	34,300
Foreign resource expenses	10	4,456	-	4,456
Undepreciated capital cost (UCC)	25	6,447	-	6,447
Share issue costs	20	25	-	25
Non-capital losses carry forward	100	71,184	-	71,184
Total tax pools		114,373	34,136	148,509

[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 flow provided by (used in) operating activities to adjusted funds flow:

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Cash flow provided by (used in) operating activities	55	1,120	(95)	1,783	4,982	(64)
Add back (deduct)						
Decommissioning expenditures	73	60	38	136	289	(53)
Change in non-cash working capital	819	91	800	568	225	152
Adjusted funds flow (1)	957	1,271	(25)	2,487	5,496	(55)

(1) See non-GAAP measures

For the year ended December 31, 2020 adjusted funds flow was $2.5 million compared to $5.5 million for the year ended December 31, 2019. The decrease of 55% was due to lower revenues from lower production volumes and lower realized prices being only partially offset by lower royalties, transportation and operating costs, lower general and administrative costs and higher realized gains on financial instruments.

For the year ended December 31, 2020, cash flow from operations was $1.8 million compared to $5.0 million for the year ended December 31, 2020. The decrease of 64% was primarily due to lower adjusted funds flow compared to the prior year and an increased use of working capital, reducing net debt, offset by lower decommissioning expenditures.

Adjusted funds flow decreased 25% for the three months ended December 31, 2020, primarily due to higher cash finance costs related to the renegotiation of the Company’s lending agreement and higher credit spreads associated with the Company’s credit facilities. Lower revenues in the fourth quarter of 2020 due to lower prices and volumes were offset by lower expenses, resulting in adjusted funds flow, excluding cash finance costs, being equivalent to the comparative quarter.

Net loss

	Three months ended			Year ended		
	Dec. 31 2020	Dec. 31 2019	% Change	Dec. 31 2020	Dec. 31 2019	% Change
Net earnings (loss)	16,891	(5,527)	(406)	(10,842)	(8,768)	24
Per boe	88.61	(24.76)	(458)	14.42	(9.92)	45
Per share – basic	1.45	(0.48)	(402)	(0.93)	(0.76)	22
Per share – diluted	1.45	(0.48)	(402)	(0.93)	(0.76)	22

The Company generated net earnings of $16.9 million for the three months ended December 31, 2020 compared to a net loss of $5.5 million for the comparative quarter. The decrease in the net loss for the three months ended December 31, 2020 was primarily due to an impairment reversal of $18.6 million in fourth quarter of 2020 versus an impairment expense of $3.8 million in the comparative quarter of 2019.

The increase in the net loss for the year ended December 31, 2020 was primarily due to lower adjusted funds flow of $3.0 million. Lower deferred income tax recovery of $1.1 million and higher impairment expense of $0.6 million were offset by lower depletion expense of $2.0 million and lower stock based compensation expense of $0.5 million.

Netback analysis

	Three months ended			Year ended		
Barrel of oil equivalent ($/boe)	Dec. 31 2020	Dec. 31 2019	% Positive (Negative)	Dec. 31 2020	Dec. 31 2019	% Positive (Negative)
Realized sales price	25.55	29.18	(12)	21.45	29.08	(26)
Royalties	(0.51)	(2.86)	82	(1.18)	(3.18)	63
Processing income	0.62	0.87	(29)	0.69	0.79	(13)
Transportation	(1.56)	(1.53)	(2)	(1.57)	(1.62)	3
Operating	(12.21)	(15.93)	23	(13.44)	(14.88)	10
Operating netback (2)	11.89	9.73	22	5.95	10.19	(42)
Realized gain (loss) – financial instruments	(0.41)	(0.35)	(17)	1.59	0.06	2,550
General and administrative	(2.31)	(2.36)	2	(2.14)	(2.59)	17
Other costs	(1.07)	-	(100)	(0.27)	-	(100)
Transaction costs	-	(0.03)	100	-	(0.13)	100
Cash finance costs	(3.06)	(1.29)	(137)	(1.82)	(1.30)	(40)
Corporate netback (2)	5.04	5.70	(12)	3.31	6.23	(47)
Unrealized gain (loss) – commodity contracts	1.53	(1.31)	217	(0.28)	(0.33)	15
Stock based compensation	(0.65)	(0.65)	-	(0.50)	(0.94)	47
Depletion and depreciation	(10.79)	(10.94)	1	(10.73)	(11.37)	6
Impairment	94.42	(16.80)	662	(5.72)	(4.24)	(35)
E&E Expense	(0.55)	-	(100)	(0.14)	(0.03)	(367)
Accretion	(0.47)	(0.76)	38	(0.38)	(0.52)	27
Gain (loss) on dispositions	-	-	-	-	0.03	(100)
Deferred income taxes	0.08	-	100	0.02	1.25	(98)
Net earnings (loss)	88.61	(24.76)	458	(14.42)	(9.92)	(45)

(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) See Non-GAAP measures

The Company's corporate netback for the quarter ended December 31, 2020 decreased 12% to $5.04 per boe versus the comparative period. The decrease is primarily due to lower royalties and operating costs per boe more than offsetting the lower realized price per boe but an increase in other costs and cash interest costs per boe in the current period versus the comparative period.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019
Production								
Oil (bbl/d)	487	531	320	582	621	641	709	768
Natural gas liquids (bbl/d)	345	410	387	431	494	501	452	473
Natural gas (mcf/d)	7,443	7,143	6,058	7,716	7,859	7,487	7,153	7,646
Total (boe/d)	2,072	2,132	1,716	2,299	2,425	2,389	2,353	2,515
Financial								
Oil and natural gas sales	4,870	4,371	2,350	4,542	6,512	5,357	6,318	7,500
Adjusted funds flow (1)	957	931	83	516	1,271	879	1,280	2,064
Per share – basic	0.08	0.08	0.01	0.04	0.11	0.08	0.11	0.19
Per share – diluted	0.08	0.08	0.01	0.04	0.11	0.08	0.11	0.19
Net earnings (loss)	16,891	(1,761)	(2,755)	(23,217)	(5,527)	(2,129)	(658)	(454)
Per share – basic	1.45	(0.15)	(0.24)	(1.99)	(0.48)	(0.18)	(0.06)	(0.04)
Per share - diluted	1.453	(0.15)	(0.24)	(1.99)	(0.48)	(0.18)	(0.06)	(0.04)

(1) See non-GAAP measures.

In the fourth quarter of 2020, production was slightly lower than the previous quarter due to normal production declines and continued minimal spending on workovers or optimization projects. Oil and natural gas sales increased by 11% in the three months ended December 31, 2020 from the previous quarter due to higher realized sales prices. Higher oil and natural gas sales were partially offset primarily by an increase in other costs and cash finance costs resulting in higher adjusted funds flow than the third quarter of 2020. The net earnings for the three months ended December 31, 2020 was $16.9 million compared to a net loss of $1.8 million in the previous quarter. The significant change in net earnings was a result of an impairment reversal of $18.6 million in the fourth quarter due to a significant improvement in commodity prices compared to the first quarter of 2020 and positive technical revisions in the Company's reserves at December 31, 2020.

In the third quarter of 2020, production was higher than the previous quarter due to shut-in production being brought back on-stream. Oil and natural gas sales increased by 86% in the three months ended September 30, 2020 from the previous quarter due to higher production volumes by 24% and higher realized sales prices. Higher oil and natural gas sales were partially offset by primarily much lower realized gains on commodity contracts resulting in higher adjusted funds flow than the second quarter of 2020. The net loss for the three months ended September 30, 2020 was $1.8 million compared to $2.8 million in the previous quarter. The major difference in the net loss was the higher adjusted funds flow in the third quarter versus the second quarter of 2020.

In the second quarter of 2020, production was lower than the previous quarter due to the shut-in of the Company's operated light oil production and associated natural gas production. Oil and natural gas sales were reduced significantly in the three months ended June 30, 2020 from the previous quarter due to lower production and lower realized sales prices other than natural gas prices. Lower oil and natural gas sales were only partially offset by realized gains on commodity contracts and reduced costs amongst all cost categories other than interest costs resulting in lower adjusted funds flow than the first quarter of 2020. The net loss for the three months ended June 30, 2020 was $2.8 million compared to $23.2 million in the previous quarter. Excluding the impairment charge of $22.3 million in the first quarter of 2020, the major differences were an unrealized loss on financial instruments of $1.1 million in the second quarter of 2020 versus an unrealized gain of $1.1 million in the first quarter of 2020.

In the first quarter of 2020, production was lower from the previous quarter due to normal production declines. Oil and natural gas sales were reduced significantly in the three months ended March 31, 2020 from the previous quarter due to lower production and lower realized sales prices. Lower oil and natural gas sales were only partially offset by realized gains on commodity contracts resulting in lower adjusted funds flow than the fourth quarter of 2019. The net loss for the three months ended March 31, 2020 was $23.2 million compared to $5.5 million in the previous quarter. The major differences were an unrealized gain on financial instruments of $1.1 million in the first quarter of 2020 and an increase in impairment expense of $18.5 million in the first quarter of 2020.

Production remained relatively flat on a quarter over quarter basis in the twelve months ended December 31, 2019 as a result of the acquisition in the first quarter of the year and proactive and successful field operations to minimize downtime. Oil and natural gas sales and adjusted funds flow increased significantly in the first quarter of 2019 due to higher oil production from the two new wells drilled in the previous fiscal period, improved benchmark pricing for oil and higher natural gas pricing through the winter. Throughout the remainder of 2019, adjusted funds flow varied with the price of natural gas production and much lower prices for propane and butane due to new marketing contract provisions with industry midstream companies. The increased loss in the last quarter of 2019 was primarily due to an impairment expense of $3.75 million related to the Company's Central Alberta Gas CGU.

LIQUIDITY AND CAPITAL RESOURCES

The full extent of the impact of COVID-19 on the Company's future financial performance is still uncertain. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, the global roll-out of a vaccine and the continued impact of the virus on financial markets.

The Company has a contemplated capital program of $1.5 to $2.0 million for 2021, primarily of discretionary expenditures and no significant commitments. The Company's expected 2021 adjusted funds flow and credit capacity should provide the liquidity to execute this capital program.

The Company's liquidity was strengthened during the current fiscal year as net debt was reduced by $2.1 million as adjusted funds flow in excess of capital expenditures was used to repay outstanding bank debt and reduce the Company's accounts payables. In addition, the Company completed a convertible debenture offering of $1.26 million. As a result, net debt is $13.2 million at December 31, 2020, down from $15.4 million at December 31, 2019, with the components set out below.

As at	Dec. 31, 2020	Dec. 31, 2019
Trade and other receivables	2,724	2,940
Prepaid expenses and deposits	640	606
Bank debt	(12,296)	(14,807)
Accounts payable and accrued liabilities	(2,767)	(3,675)
Decommissioning obligations	(342)	(422)
Convertible debentures	(1,194)	-
Net debt (1)	(13,235)	(15,358)

(1) See Non-GAAP measures.

Balance sheet strength and flexibility remain a priority through an even more challenging environment with the recent drop in world crude oil prices. The Company continues to proactively consider funding alternatives, including a further 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 during the historic low acquisition and disposition market. 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 1, 2020, the Company has a revolving, operating demand loan ("Operating Facility") with an Alberta based financial institution ("Lender") with a facility limit of $15.0 million (December 31, 2019 - $18.5 million). Additionally, Clearview has a $6.25 million term loan through its Lender under the Business Credit Availability Program ("BCAP"), supported by the Export Development Canada ("EDC") Guarantee ("EDC Facility") providing a total credit capacity of $21.25 million.

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 EDC Facility is a non-revolving term facility to be used exclusively to provide additional liquidity for the Company's business operations. The facility can be used to pay operating expenses, G&A expenses, interest on the Operating Facility and pay down temporary advances on the Operating Facility. The EDC Facility cannot be used to repay or refinance permanent reductions to the Operating Facility or to make shareholder contributions, shareholder loans, share buy backs or pay any bonuses or increase executive compensation.

The EDC Facility is payable on demand by the Lender and is non-revolving. The facility has a term of five years with the EDC providing a guarantee to the Company's lender for 80% of the principal amount outstanding. The principal amount outstanding must be repaid no later than 50% at the end of the fourth year with the remaining principal outstanding due for repayment at the end of the fifth year.

The Operating Facility and EDC Facility are 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 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 3.75% to 6.75%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0. Effective December 1, 2020, the Company is paying 8.70% (lender's prime rate of 2.45% plus a credit spread of 6.25%) on prime based loans.

Guaranteed notes are subject to the Canadian Dollar Offered Rate ("CDOR") plus a stamping fee of 4.75% to 7.75%, 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. Effective December 1, 2020, the Company is paying 7.75% (CDOR of 0.50% plus a stamping fee of 7.25%) on guaranteed notes.

Under the EDC Facility, the loan is subject to an interest rate of lender prime plus a credit spread of 3.75% to 6.75%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0. Effective December 1, 2020, the Company is paying 8.70% (lender's prime rate of 2.45% plus a credit spread of 6.25%) on the EDC Facility. The Company paid and will be required to pay an upfront fee of 1.8% of the outstanding balance, annually to the EDC.

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 and EDC 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, 2020, the Company's working capital ratio for purposes of the lender's working capital covenant was 4.0:1 (1.8:1 at December 31, 2019). 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, 2020 was 2.2. In addition, the Company will now be required to maintain commodity swap contracts for 50% (approximately 3,400 GJ per day) of its natural gas production volumes and 300 barrels per day of its oil production volumes through to the next annual review date. The Company has satisfied the requirement to contract a portion of its production volumes as per the lending agreement.

At December 31, 2020, the Company had $6.0 million of guaranteed notes, $49 thousand in prime-based loans and $10 thousand in letters of credit outstanding on the Operating Facility and $6.25 million outstanding on the EDC Facility.

The next credit review is scheduled to be completed by no later than October 31, 2021. 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.

In addition, on December 1, 2020, the Company issued $1.26 million of unsecured convertible debentures at a price of $100 per debenture. 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, 2021. During the remainder of the term, the Company may redeem the debentures over the term based on the following terms:

Year 2 – 110% of the principal amount plus accrued interest
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 Company is committed to future minimum payments for natural gas transmission and office space. The Company has a lease for office space which expires June 30, 2021 and may be cancelled by either the Company or the landlord on one month's notice to the other party. The following is a summary of the Company's future minimum contractual obligations and commitments as of December 31, 2020.

	2021	2022	2023	2024	2025	Thereafter
Bank debt	12,296	-	-	-	-	-
Accounts payable and accrued liabilities	2,767	-	-	-	-	-
Decommissioning obligations	342	425	425	425	425	24,687
Convertible debentures	-	-	-	-	1,262	-
Gas transportation	7	3	-	-	-	-
Office lease	54	-	-	-	-	-
Total	15,466	428	425	425	1,687	24,687

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 27, 2021, the Company has 11,671,387 voting common shares outstanding and 568,100 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 $4.50 and $1.25.

Vesting period	Options - $4.50	Options - $5.00	Options - $1.25	Total
Currently vested	154,000	92,500	-	246,500
Vesting in the future in the three months ending				
December 31, 2021	-		107,200	107,200
December 31, 2022	-		107,200	107,200
December 30, 2023	-		107,200	107,200
Total	154,000	92,500	321,600	568,100

For further details about the options refer to Note 10 to the financial statements as at and for the period ended December 31, 2020.

RELATED PARTY TRANSACTIONS

There were no related party transactions in the twelve months ended December 31, 2020.

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, 2020 and December 31, 2019. Certain estimates and judgments are described in Note 2 to the audited financial statements for the periods ended December 31, 2020 and December 31, 2019.

Impact of COVID-19

In March 2020, the World Health Organization declared a global pandemic following the rapid spread of a novel strain of the coronavirus ("COVID-19"). The outbreak and subsequent measures enforced to limit the spread of the pandemic contributed to volatility in financial markets. The pandemic has adversely impacted global trade, including significantly reducing worldwide demand for oil and natural gas.

The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare the financial statements, particularly related to recoverable amounts.

There is a high degree of uncertainty regarding the estimates and assumptions used in determining recoverable amounts including future crude oil and natural gas commodity prices, foreign exchange rates, discount rates and the Company's future production of crude oil and natural gas. As the understanding of the longer-term impacts of COVID-19 develop, the estimates and assumptions used in determining the recoverable amounts could change and there could be a material financial affect in future periods.

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 1.49% 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. In estimating the fair value of decommissioning obligations which are a component of a business combination, the Company uses a market discount rate, which was 13% over the past two years.

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, 2020 and December 31, 2019. 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.

NEW ACCOUNTING POLICIES

New accounting standards:

During the year ended December 31, 2020, the Company adopted the following new accounting standard.

Business Combinations

On January 1, 2020, the Company adopted the amendments to IFRS 3, "Business Combinations", to clarify whether a transaction results in an asset acquisition or a business acquisition. The amendments include an election to use a concentration test. This is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets are concentrated in a single identifiable asset or a group of similar identifiable assets. If the concentration test is not applied, or the concentration test fails, then the assessment focuses on the existence of a substantive process. The standard will be applied prospectively. No business combinations were completed during the year ended December 31, 2020.

New accounting standards not yet adopted:

On January 23, 2020, the International Accounting Standards Board announced an amendment to IAS 1 "Presentation of financial statements re; classification of liabilities as current or non-current which is effective for annual periods beginning on or after January 1, 2023. The amendment clarifies that the classification of liabilities as current or non-current should be based on rights that are in existence at the end of the reporting period. The Company does not plan to early adopt these amendments.

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 13 of the audited financial statements for the year ended December 31, 2020 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.

Non-GAAP measures

The Company's management uses and reports certain measures not prescribed by International Financial Reporting Standards ("IFRS") (referred to as "non-GAAP measures") in the evaluation of operating and financial performance.

Operating netback is a non-GAAP measure used by the Company to assess its operating results. The Canadian Oil and Gas Evaluation Handbook ("COGEH") describes netback as "an operations indicator to assess operating priorities and evaluate smaller capital expenditures normally associated with field maintenance and improvement". The COGEH provides guidance that "the netback calculation takes the price received for a unit of production at a point in time and deducts from it all production costs, royalties and production taxes to find the cash netback to the producer from each barrel of oil or mcf of sales gas". The Company computes the operating netback for the Company directly from the applicable amounts on the Statements of Operations in the financial statements being oil and natural gas sales and processing income less royalties, production and transportation costs. This amount divided by the associated production volume (usually in boe's) provides a per unit amount.

Adjusted funds flow is a non-GAAP measure derived from cash flow from operating activities excluding decommissioning expenditures and changes in non-cash working capital. The adjusted funds flow amount represents funds available for capital and abandonment expenditures, repayment of net debt or distribution to shareholders.

Corporate netback is the adjusted funds flow amount divided by the total production for the period and represents the cash margin received on each barrel of oil equivalent sold.

Net debt consists of current assets (excluding financial derivatives) less current liabilities (excluding financial derivatives) less convertible debentures. Net debt is used to assess financial strength, capacity to finance future development and manage liquidity risk.

Operating netback, adjusted funds flow, corporate netback and net debt do not have any standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of a similar measure for other companies. The Company uses these terms as an indicator of financial performance because such terms are used internally in managing and governing the Company and are often utilized by investors and other financial statement users to evaluate producers in the oil and natural gas industry.

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

Clearview Resources Ltd.
2400, 635 8th Avenue SW
Calgary, AB, T2P 3M3
Telephone 403-265-3503

Directors
Lindsay R. Stollery, Board Chair
Richard G. Carl
Todd L. McAllister
Harold F. Pine
Murray K. Scalf
David M. Vankka
Tim S. Halpen

Officers and Management
Tony Angelidis, President and Chief Executive Officer
Brian Kohlhammer, VP Finance and Chief Financial Officer
Darcy Ries, VP Engineering and Chief Operating Officer
Renee Miles, Land Manager
Dmitriy Shlyonchik, Operations Manager
Lynda Christie, Controller

Reserves Evaluator
McDaniel & Associates Consultants Ltd.
2200, 255 – 5th Avenue SW
Calgary, AB, T2P 3G6

Auditors
KPMG LLP
Suite 3100, 205 - 5th Avenue SW
Calgary, AB, T2P 4B9

Lender
ATB Financial
600, 585 – 8th Ave SW
Calgary, AB, T2P 1G1

Legal Counsel
Dentons Canada LLP
1500, Bankers Court, 850 – 2nd Street SW
Calgary, AB, T2P 0R8

Transfer Agent
Computershare
11th Floor, South Tower, 100 University Avenue
Toronto, ON, M5J 2Y1