Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

December 31, 2018

HIGHLIGHTS FOR THE NINE MONTH PERIOD ENDED DECEMBER 31, 2018

- The Company drilled and completed its first operated, extended reach, horizontal well at Wilson Creek 15-20-44-4W5M. The well targeted the Cardium formation and was brought on-stream in August 2018. Clearview also drilled and completed the Company's second operated, extended reach, horizontal well targeting the Bluesky formation at Windfall 1-3-59-15W5M. This well was brought on-stream in November 2018. Results to date have exceeded the Company's expectations.

- Clearview closed a private placement during the fourth quarter of 2018, issuing 210,390 common shares at a price of $6.25 per share for gross proceeds of $1.3 million and 101,543 flow-through common shares at a price of $7.00 per share for gross proceeds of $0.7 million.

- On April 16, 2018, the Company closed the acquisition of Bashaw Oil Corp. ("Bashaw") through a share for share exchange. Clearview issued 1,560,046 voting common shares to the shareholders of Bashaw.

- On April 10, 2018, the Company closed the disposition of a non-core, non-operated light oil property located in southern Alberta for $3.4 million and on December 20, 2018 closed the disposition of two minor, non-core production units for proceeds of $0.1 million.

- Oil production increased 54% to 668 barrels per day ("bbl/d") in the three months ended December 31, 2018, from the comparative period through successful drilling and optimization projects. Total production increased 5% to 2,229 barrels of oil equivalent per day ("boe/d") in the three months ended December 31, 2018 versus the comparative period.

- Realized sales price was $27.82 per barrel of oil equivalent ("boe") for the nine months ended December 31, 2018 compared to $26.30 per boe in the prior year, an increase of 6%, while the last quarter of 2018 was down 17% to $22.36 per boe due to lower oil and natural gas liquids prices associated with a significant widening of light oil differentials.

- Operating costs per boe increased modestly to $15.83 per boe for the three months ended December 31, 2018, an increase of 1% over the comparative period. For the nine months ended December 31, 2018, operating costs were $15.69 per boe, up 7% versus the comparative period.

- General and administrative costs per boe were unchanged for the three months ended December 31, 2018 versus the comparative period and notably down 13% for the nine months ended December 31, 2018 versus the prior year.

Clearview Resources Ltd.
Management Discussion and Analysis (MD&A)
December 31, 2018

Change in Year End

During the year, the Board of Directors approved changing the Company's fiscal year end from March 31 to December 31 to have the Company's year-end financial statements more comparative with the majority of its industry competitors. Consequently, the management discussion and analysis ("MD&A") is a review of the financial position and results of operations of the Company for the three months ended December 31, 2018 as compared to the three months ended December 31, 2017 for quarterly comparisons and the nine months ended December 31, 2018 as compared to the twelve months ended March 31, 2018 for yearly comparisons.

The MD&A should be read in conjunction with the Company's audited financial statements and accompanying notes for the periods ended December 31, 2018 and March 31, 2018. 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 23, 2019.

Refer to page 25 for information about non-GAAP measures, page 26 for information on forward-looking statements and page 27 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. Additional information about the Company is 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	5,762	87%	Yes
	Pembina	Liquids rich natural gas	1,533	80%	Yes
	Wilson Creek	Light oil and liquids rich natural gas	4,111	60%	Yes
	Windfall	Light oil	5,119	100.0%	Yes
	Caribou	Light oil	617	63.3%	Yes
Other	Bantry	Medium oil	411	40.0%	No
	Carstairs (Unit)	Liquids rich natural gas	717	17.0%	No
	Lindale (Unit)	Light oil with associated natural gas and liquids	311	10.6%	No
	Crossfield (Unit)	Liquids rich natural gas	49	4.2%	No
	Miscellaneous	Various	13	Various	Mixed
Total			18,643		

[1] mboe of total proved plus probable reserves at December 31, 2018 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 2018	Dec. 31 2017	Dec. 31 2018	Mar. 31 2018	Mar. 31 2017
Oil and natural gas sales	4,585	5,254	16,273	20,286	7,112
Adjusted funds flow (1)	511	1,189	1,852	3,679	(408)
Per share – basic	0.05	0.14	0.18	0.44	(0.10)
Per share – diluted	0.05	0.14	0.18	0.44	(0.10)
Cash flow from operations	1,312	525	1,088	4,337	(983)
Per share – basic	0.13	0.06	0.11	0.51	(0.25)
Per share - diluted	0.13	0.06	0.11	0.51	(0.25)
Net earnings (loss)	(2,083)	(2,435)	(4,832)	(8,460)	(1,896)
Per share – basic	(0.20)	(0.29)	(0.48)	(1.00)	(0.48)
Per share – diluted	(0.20)	(0.29)	(0.48)	(1.00)	(0.48)
Total assets			80,752	72,714	71,156
Total long term liabilities			22,645	18,873	15,607
Net debt (1)			18,186	14,154	14,604
Total capital expenditures – net (2)			6,172	6,375	28,706

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

The Company experienced significant growth in oil and natural gas sales and adjusted funds flow following the acquisition of producing oil and gas properties in the fourth quarter of the fiscal year ended March 31, 2017 and the acquisition of a light oil property in the fourth quarter of the fiscal year ended March 31, 2018. Increased oil and natural gas liquids prices also contributed to the improvement in adjusted funds flow but declining natural gas prices reduced the positive effect of increased natural gas production. For the fiscal year ended December 31, 2018, oil and natural gas sales and adjusted funds flow were reduced by there being three fewer months of operations, significantly lower oil prices in the last quarter of the year and reduced natural gas prices. The net loss was impacted by these factors in addition to a loss on the disposition of property for $0.7 million in the current period and an impairment in the previous year of $1.4 million. Long term liabilities have increased as a result of additional decommissioning obligations associated with the acquisitions over the past three years.

DISCUSSION OF OPERATIONS

Business combination

On April 16, 2018, Clearview acquired all of the issued and outstanding common shares of Bashaw Oil Corp. ("Bashaw") through a share for share exchange with the issuance of 1,560,046 voting common shares of the Company. The operations of Bashaw have been included in Clearview's results commencing on April 16, 2018. Bashaw Oil Corp. was subsequently amalgamated into Clearview Resources Ltd.

The total consideration paid by Clearview was approximately $8.2 million based on a share price, agreed upon by the two parties, for Clearview of $5.28 per share, which was determined to be fair value at closing. Transaction costs of $16 thousand were recorded in earnings.

The acquisition of Bashaw has been accounted for as a business combination. The net assets have been allocated as follows:

Acquisition Date	April 16, 2018
Consideration	
Share consideration (1,560,046 common shares)	8,237
Net assets at estimated fair value	
Working capital (including cash of $1,671)	1,710
Property, plant and equipment	7,725
Decommissioning obligations	(1,198)
Net assets	8,237

Capital expenditures and drilling activity

	Three months ended			Periods ended		
	Dec. 31 2018	Dec.31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Land	2	6	(67)	33	354	(91)
Drilling, completions, equipping	3,902	695	461	9,422	1,947	384
Facilities	(388)	39	(1,095)	142	559	(75)
Other	(24)	60	(140)	3	139	(98)
Capital invested	3,492	800	337	9,600	2,999	220
Disposition of properties	(128)	-	100	(3,495)	-	100
Net capital invested	3,364	800	321	6,105	2,999	104
Acquisition of properties	-	-	-	67	3,376	(98)
Total capital expenditures	3,364	800	321	6,172	6,375	(3)

Two (1.85 net) extended reach horizontal light oil wells were drilled during the year, one at Wilson Creek 15-20-44-4 W5 in the Cardium formation and the other at Windfall 1-3-59-15 W5 into a Bluesky/Gething channel. The second well was completed and equipped in the three months ended December 31, 2018. Both wells were successful and brought on production in September and November of 2018, respectively. Net capital costs for the two wells were $9.2 million.

Earlier in the year, on April 10, 2018, the Company closed the disposition of the oil property reported as assets held for sale at the end of the prior year for proceeds of $3.4 million, after closing adjustments. The proceeds from the disposition were immediately applied to reduce the Company's bank debt. No gain or loss on disposal was recorded as a result of this transaction.

During the three months ended December 31, 2018, the Company sold non-core properties in the Southern Alberta Oil CGU for net proceeds of $126 thousand. The acquirer assumed the decommissioning obligations associated with the properties. The Company recorded a loss on the disposition of the properties in the statement of operations of $0.7 million.

During the year ended December 31, 2018, the Company acquired working interests of several joint venture partners in its Central Alberta Gas CGU for cash consideration of $67 thousand.

Production

Production is summarized in the following table:

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Oil – bbl/d	668	434	54	568	437	30
Natural gas liquids – bbl/d	437	514	(15)	445	475	(6)
Total liquids – bbl/d	1,105	948	17	1,013	912	11
Natural gas – mcf/d	6,745	7,085	(5)	6,682	7,211	(7)
Total – boe/d	2,229	2,129	5	2,127	2,113	1

Production for the quarter ended and period ended December 31, 2018 increased by 5% and 1% over the respective comparative periods due to the acquisition of Bashaw in the first three months of the year and two highly successful new light oil wells brought on production in the second half of the year. With a focus on acquiring and drilling light oil opportunities, oil production increased 30% for the nine months ended December 31, 2018 and 54% for the three months ended December 31, 2018 versus the comparative periods. Natural gas liquids, generally associated with natural gas production, decreased more than natural gas as increased natural gas production was realized as solution gas with the two new light oil wells brought on stream.

Production, on a boe/d basis, from the Company's core properties was as follows:

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Wilson Creek	585	423	38	463	431	7
Northville	879	754	17	757	847	(11)
Pembina	201	260	(23)	213	254	(16)
Caribou	158	133	19	157	138	14
Windfall	276	-	100	228	29	686
Total – boe/d	2,099	1,570	34	1,818	1,699	7
% of total production	94%	74%	28	85%	80%	6

Clearview's production portfolio for the quarter ended December 31, 2018 was weighted 30% to oil, 20% to natural gas liquids and 50% to natural gas. For the period ended December 31, 2018 the production mix was weighted 27% to oil, 21% to natural gas liquids and 52% to natural gas. The 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. The Company has very little dry natural gas production (approximately 300 mcf/d or 50 boe/d) which is at risk of being shut-in during periods of low natural gas prices.

Benchmark prices and economic parameters

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	58.82	55.40	6	65.38	53.69	22
Oil – Edmonton Par ($/bbl)	42.68	68.80	(38)	68.41	64.85	5
Differential – Light oil ($/bbl) (1)	34.94	1.60	2,080	16.94	3.96	328
NGLs - Pentane ($/bbl)	64.45	73.71	(13)	78.98	69.96	13
NGLs – Butane ($/bbl)	13.51	53.19	(75)	28.74	45.04	(36)
NGLs – Propane ($/bbl)	24.13	40.29	(40)	24.99	29.79	(16)
Natural gas – AECO ($/mcf)	1.56	1.72	(10)	1.31	2.05	(36)
Exchange rate – US$/Cdn$	0.756	0.787	(4)	0.765	0.780	(2)

(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 had been recovering in the calendar year 2018 from WTI US $50.00 per barrel at the end of 2017 to US $70.00 per barrel in September of 2018. Through most of the year, Canadian oil prices increased as well despite a gradual increase in the light differentials between US and Canadian crude prices. In the fourth quarter of 2018, restrictions on the export capacity of oil pipelines from Canada to the United States took a severe toll on Canadian crude oil prices. The light oil price differential for Canadian crude widened significantly beginning in October 2018, increasing from approximately Cdn $9.00 per barrel to over Cdn $46.00 per barrel in December 2018. Light oil prices in Canada, which had been as high as Cdn $82.00 per barrel in July 2018, dropped to under Cdn $20.00 in December 2018. Despite the severe drop in light oil prices in the fourth quarter of 2018, Edmonton Par averaged Cdn $68.41 per barrel for the period ended December 31, 2018, a 5% increase over the previous year. Prices for the three months ended December 31, 2018 were Cdn $42.68 per barrel, a decrease of 38% as compared to the same quarter of the prior year.

Propane prices averaged $24.99 per barrel for the year ended December 31, 2018, a decrease of about 16 percent from the previous year. Propane prices were reasonably steady for most of the period but were negatively affected by the drop in WTI in the fourth quarter of the period. For the three months ended December 31, 2018, propane prices were $24.13 per barrel, 40% lower than the comparative period of the prior year.

Butane prices averaged $28.74 per barrel for the period ended December 31, 2018, a decrease of about 36 percent from the previous year. Butane prices declined continuously through the period ended December 31, 2018 due to an oversupply of butane in Canada associated with the growth in liquids rich natural gas production in western Canada. Butane prices for the three months ended December 31, 2018 were $13.51 per barrel, a decrease of 75% as compared to the same period of the prior year. Demand for butane as a diluent for heavier crude oils decreased significantly in the fourth quarter due to lower shipment of heavier crudes due to low prices.

Pentane prices averaged $78.98 per barrel for the period ended December 31, 2018, an increase of about 13 percent from the previous year. The increase in pentane prices is consistent with the increase in WTI for the year of 22% and a slightly decreasing US$/Cdn$ exchange rate. For the three months ended December 31, 2018, pentane prices were $64.45 per barrel, 13% lower than the comparative period of the prior year, due to lower demand as a diluent for heavier crude oils resulting from low prices for heavy crudes.

Natural gas prices continued to be low on average other than short term higher prices in the winter months associated with colder weather and high heating demand. AECO natural gas prices averaged $1.31 per mcf for the period ended December 31, 2018, a decrease of 36% as compared to the prior year. For the three months ended December 31, 2018, AECO natural gas price averaged

$1.56 per mcf, a 10% decrease over the comparative period as a result of mild winter weather during the period.

Realized sales prices

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Oil – $/bbl	36.20	62.78	(42)	58.87	58.63	-
NGLs – $/bbl	31.17	35.16	(11)	36.26	33.13	9
Natural gas – $/mcf	1.79	1.64	9	1.44	1.98	(27)
Total – $/boe	22.36	26.83	(17)	27.82	26.30	6

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, 2018, the Company's realized oil prices were lower by 42% than the comparative quarter as a result of a significant widening in light oil price differentials. For the period ended December 31, 2018, realized oil prices were unchanged.

Natural gas liquids prices were lower by 11% in the last quarter of the current year as compared to the same quarter of the prior year. This decrease was primarily due to lower benchmark propane and pentane prices. For the period ended December 31, 2018, natural gas liquids prices were 9% higher than the previous year, primarily due to higher pentane prices for the year.

The Company's realized price for natural gas was higher by 9% for the three months ended December 31, 2018. This compares to a 10% decrease in the benchmark AECO price over the same period. For the period ended December 31, 2018, the Company's natural gas price was lower by 27% versus the decrease in AECO of 36% over the year. Realized natural gas prices being better than the change in AECO is due to the higher price than AECO received for natural gas production at the Company's Windfall property. Windfall natural gas production is very liquids rich and sold on the Alliance pipeline system at the posted Alliance Transfer Point ("ATP") price. For the three months ended December 31, 2018, the Company received an incremental $0.37 per mcf for heating content of the Windfall natural gas and $1.44 per mcf for the ATP price adjustment over AECO, before transportation costs. For the period ended December 31, 2018, the Company received an incremental $0.32 per mcf for heating content of the Windfall natural gas and $0.93 per mcf for the ATP price adjustment over AECO, before transportation costs. Windfall's natural gas production represented 8.9% and 8.3% of the Company's production for the three months and period ended December 31, 2018, respectively.

On a boe basis, the Company's realized price was 17% lower for the three months ended December 31, 2018 than the comparative period, primarily due to lower oil prices, and higher by 6% for the period ended December 31, 2018.

Revenues

Oil and natural gas sales

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Oil	2,223	2,508	(11)	9,198	9,345	(2)
Natural gas liquids	1,253	1,676	(25)	4,438	5,740	(23)
Total liquids	3,476	4,184	(17)	13,636	15,085	(10)
Natural gas	1,109	1,070	4	2,637	5,200	(49)
Total sales	4,585	5,254	(13)	16,273	20,286	(20)
Per boe	22.36	26.83	(17)	27.82	26.30	6

Crude oil sales decreased 11% in the three months ended December 31, 2018 as an increase in oil production volumes of 54% from acquisitions and successful drilling was more than offset by a 42% decrease in realized oil prices.

Natural gas liquids revenues were lower by 25% in the quarter ended December 31, 2018 as production was lower by 15% and realized natural gas liquids prices were lower by 14%.

Natural gas revenue increased 4% in the quarter ended December 31, 2108 as lower production volumes of 5% were more than offset by a 9% increase in the realized natural gas price due to the natural gas sales at Windfall.

The 20% decrease in oil and gas sales for the period ended December 31, 2018 is primarily due to three months less of operations in the current year as production per day for the year was 1% higher than the previous year and the realized sales price per boe was 6% higher than the previous 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 received over 96.6% of its monthly production revenue from its customers on this day throughout the year. The remaining 3.4% 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, Crossfield, 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.

Processing income decreased to $102 thousand for the three months ended December 31, 2018, a 50% decrease from the comparative quarter ended December 31, 2017. The decrease primarily reflects an adjustment to processing income on a non-operated property related to prior years for $70 thousand and lower volumes being processed at some of the Company's facilities in the quarter. The decrease in processing income for the year reflects three months less of operations and the adjustment to processing income on a non-operated property related to prior years for $70 thousand.

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Processing income	102	203	(50)	465	810	(43)
Per boe	0.50	1.03	(52)	0.80	1.05	(24)

Risk management activities

Clearview enters into financial 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 following table lists the financial commodity contracts held by the Company that were outstanding as of December 31, 2018:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
Nov. 1, 2018	Mar. 31, 2019	GJ/day	1,000	AECO - Monthly	$2.07

The fair value of the financial contracts outstanding as at December 31, 2018 is estimated to be an asset of $64 thousand. At March 31, 2018 the fair value of the financial contracts outstanding was a liability of $1.1 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 period ended December 31, 2018, the Company recognized an unrealized gain of $1.2 million on its outstanding commodity contracts versus an unrealized loss of $1.2 million in the prior year ended March 31, 2018. In the three months ended December 31, 2018, Clearview recorded an unrealized gain on commodity contracts of $0.8 million as compared to an unrealized loss of $1.2 million in the three months ended December 31, 2017. The unrealized loss in the three months and fiscal year ended December 31, 2018 is the difference between the fair values of the commodity contracts at December 31, 2018 and the fair values of outstanding commodity contracts at the respective prior reporting periods.

For the year ended December 31, 2018, the Company had a realized loss on commodity contracts of $0.8 million versus a realized gain in the prior year of $0.6 million. During the three months ended December 31, 2018, the Company recorded a realized gain of $0.4 million versus a realized gain of $0.3 million in the comparative quarter. With the significant drop in West Texas Intermediate in the last three months of 2018, the Company unwound its crude oil commodity contract for 2019 of 100 barrels per day at WTI/Cdn $90.00 per barrel resulting in a gain of $0.7 million in the month of December 2018.

The Company has executed additional commodity price contracts for its natural gas production subsequent to December 31, 2018 as follows:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
February 1, 2019	October 31, 2019	GJ/day	1,000	AECO 5A - Financial	$1.18
February 1, 2019	December 31, 2019	GJ/day	1,000	AECO 5A - Financial	$1.52
February 1, 2019	February 28, 2019	GJ/day	1,000	AECO 5A - Financial	$2.10
March 1, 2019	December 31, 2019	GJ/day	1,000	AECO 5A - Physical	$1.51
March 1, 2019	March 31, 2019	GJ/day	1,000	AECO 5A - Physical	$1.75
April 1, 2019	April 30, 2019	GJ/day	1,000	AECO 5A - Physical	$1.41
January 1, 2020	December 31, 2020	GJ/day	1,000	AECO 5A - Financial	$1.57
January 1, 2020	December 31, 2020	GJ/day	1,000	AECO 5A - Physical	$1.61

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

Royalties

	Three months ended			Periods ended		
Amount	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Crown – oil	217	138	57	1,088	626	74
Crown – natural gas liquids	421	455	(7)	1,378	1,567	(12)
Crown – natural gas	57	151	(62)	141	545	(74)
Gas cost allowance	(594)	(519)	14	(1,528)	(1,598)	(4)
Total Crown	101	225	(55)	1,079	1,140	(5)
Freehold	86	179	(52)	391	579	(32)
Gross over-riding	165	165	-	514	570	(10)
Total royalties	352	569	(39)	1,984	2,289	(13)
Per boe	1.72	2.91	(41)	3.39	2.97	14

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			Periods ended		
Royalty rate	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Total Crown	2.2%	4.3%	(49)	6.6%	5.6%	18
Freehold	1.9%	3.4%	(44)	2.4%	2.9%	(17)
Gross over-riding	3.6%	3.1%	16	3.2%	2.8%	14
Total royalties	7.7%	10.8%	(29)	12.2%	11.3%	8

The overall royalty burden for the fiscal year increased by 8% to a rate of 12.2% versus 11.3% for the prior year. Crown royalty rates were higher due to increased oil volumes achieved from recompletion operations and as a result of higher crude oil prices for most of the period. Gross over-riding royalties increased due to higher oil prices and the lands on which new wells were drilled being encumbered by new over-riding royalties.

The decrease in royalty rate for the three months ended December 31, 2018 of 29% is primarily due to the lower royalty rates of 5% associated with the new light oil production and the reduced royalty rates for crude oil and natural gas liquids due to very low prices for all products as discussed above. Gross over-riding royalties increased in the three months ended December 31, 2018 due to the lands on which new wells were drilled being encumbered by new over-riding royalties.

Transportation expenses

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Transportation costs	291	253	15	769	1,070	(28)
Per boe	1.42	1.29	10	1.32	1.39	(5)

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. The Company has 87% of its natural gas volumes under firm service transportation contracts with NGTL and operators of midstream facilities that process the Company's natural gas production. Transportation expense increased 15% in the three months ended December 31, 2018 due to higher trucked volumes as oil production increased 54% over the same three months versus the comparative period.

For the period ended December 31, 2018, transportation costs were lower by 28%. The decrease is a combination of 30% more oil volumes being trucked per day, offset by lower trucking rates negotiated with the trucking companies hauling the Company's oil production to the sales terminals, higher transportation costs for Windfall natural gas production sold on the Alliance pipeline system and three months less of transportation costs than the previous year.

Operating expenses

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Operating costs	3,247	3,078	5	9,177	11,334	(19)
Per boe	15.83	15.72	1	15.69	14.69	7

The Company continues to focus on reducing production costs given the prolonged period of low 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 for the three months ended December 31, 2018 were $15.83 per boe, higher by 1%, than the comparative quarter of the prior year, at $15.72/boe. For the period ended December 31, 2018, operating costs increased 7% on a per boe basis. This increase primarily reflects an increase in repairs and maintenance, workovers, fuel and power and lease rentals partially offset by lower processing and treating fees.

General and administrative expenses

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Gross costs	548	466	18	1,775	2,487	(29)
Overhead recoveries	(100)	(39)	156	(305)	(272)	12
Total G&A expenses	448	427	5	1,470	2,215	(34)
Per boe	2.18	2.18	-	2.51	2.87	(13)

General and administrative costs, net of recoveries, increased 5% in the three months ended December 31, 2018 versus the comparative period as increased costs were offset by an increase in overhead recoveries as a result of being an operator of more production and the ability to invoice working interest partners for administrative functions in accordance with industry standards.

For the period ended December 31, 2018, general and administrative costs, net of recoveries, decreased 34% due to the current year reflecting three months less of costs and the prior year including termination payments to several officers and employees of the Company.

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 June and August 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. During the current period, the Company granted options to acquire 463,500 voting common shares with an exercise price of $5.00 per share under option, with expiration and vesting as described above. The assumptions used in determining the fair values are as follows:

Year ended	December 31, 2018	March 31, 2018
Exercise price	$5.00	$5.00
Volatility	73%	73%
Expected option life	6.7 years	7.0 years
Dividend	$nil	$nil
Risk-free interest rate	2.25%	0.5%

The Company is not listed on a stock exchange. The exercise prices were based on recent issue prices for the voting common shares. The estimate of volatility is based on the volatility of the entire sector of oil and gas producers on a Canadian stock exchange.

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Stock based compensation	362	228	59	695	938	(26)
Per boe	1.77	1.16	53	1.19	1.22	(2)

Stock based compensation expense for the three months ended December 31, 2018 was higher by 59% versus the comparative period. The increase in expense is primarily due to options granted to a director and numerous employees in the second quarter. For the period ended December 31, 2018, the expense was lower by 26% as a result of the reversal of stock based compensation for options cancelled which were previously held by option holders no longer employed with Clearview and less amortization due to the there being one less quarter in the year ended December 31, 2018 versus the prior year.

Depletion, depreciation and impairment

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Depletion	2,257	2,107	7	6,159	8,265	(25)
Depreciation	2	-	100	6	7	(14)
Impairment	-	-	-	-	1,404	(100)
Total	2,259	2,107	7	6,165	9,676	(36)
Per boe – depletion	11.00	10.76	2	10.53	10.71	(2)
Per boe - depreciation	0.01	-	100	0.01	0.01	-
Per boe - impairment	-	-	-	-	1.82	(100)
Total	11.01	10.76	2	10.54	12.54	(16)

The Company calculates depletion on property, plant and equipment using the unit-of-production method based on proved plus probable reserves. Depreciation is calculated based on the useful lives of office equipment and furniture. The increase in depletion for the three months ended December 31, 2018 is primarily due to greater production volumes. Production increased 5% versus an increase in the depletion expense of 7%. Depletion for the period ended December 31, 2018 was 25% lower than the prior year. This decrease reflects the fact that there is one less quarter of production in the period ended December 31, 2018 versus the prior year.

At December 31, 2018, Clearview identified indicators of impairment, primarily due to the volatility of Canadian crude oil prices in the last three months of the year due to the significant widening in light oil differentials. In addition, forecast commodity prices had declined from the previous year, primarily natural gas. Clearview performed an impairment test on all its CGU's based on fair value less cost to sell. The impairment test indicated no write-down was required of the Company's producing assets.

Transaction costs

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Transaction costs	-	-	-	16	96	(83)
Per boe	-	-	-	0.03	0.12	(75)

Transactions costs for the period ended December 31, 2018 were lower by 83% as compared to the prior year. The reduction in transaction costs was due to the majority of the transaction costs associated with the business combination with Bashaw Oil Corp. which closed on April 16, 2018 being recorded in the prior year.

Finance costs

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Interest on bank debt	258	200	29	688	828	(17)
Credit facility fees and costs	23	21	10	26	153	(83)
Cash finance costs	281	221	27	714	981	(27)
Accretion expense (1)	57	95	(40)	328	358	(8)
Total finance costs	338	316	7	1,042	1,339	(22)
Per boe – cash finance costs	1.37	1.13	21	1.22	1.27	(4)
Per boe – accretion expense	0.28	0.49	(43)	0.56	0.46	22

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

Cash finance costs include interest on bank debt and lender fees plus minor amounts for miscellaneous interest and penalties charged by vendors and taxing authorities. Interest on bank debt in the three months ended December 31, 2018 increased due to increases in the bank prime lending rate during the year and increasing outstanding loan balances as the Company undertook its planned capital program.

The interest rate on prime based borrowings under the credit facility has increased over the past two years as follows:

- July 2017 - from 5.70% to 5.95% - increase in the prime rate,
- September 2017 - from 5.95% to 6.20% - increase in the prime rate,
- January 2018 - from 6.20% to 6.45% - increase in the prime rate,
- July 2018 – from 6.45% to 6.70% - increase in prime rate, and
- October 2018 – from 6.70% to 6.95% - increase in prime rate.

The average rate for prime based borrowings during the period ended December 31, 2018 was 6.7%.

The Company also has the option of borrowing using the lender's guaranteed notes which are subject to a current stamping fee of 4.0% per annum plus the guaranteed note rate for 30, 60, 90 and 180 day terms. Guaranteed notes resulted in an average rate of approximately 5.9% during the period ended December 31, 2018.

In addition, the Company pays its lender a standby fee of 1.25% on the difference between the credit facility of $21.0 million and the combined prime rate borrowings and guaranteed notes borrowings.

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 2 to 45 years due to the long-term nature of certain assets. Accretion expense decreased in the three months ended December 31, 2018 due to a lower risk-free interest rate used to calculate the accretion expense. The decrease in accretion expense for the period end December 31, 2018 as compared to the prior year is a result of the current year only representing accretion expense for nine months versus twelve months in the prior year.

Income taxes

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Deferred income tax recovery	5	-	100	76	-	100
Per boe	0.03	-	100	0.13	-	100

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 at December 31, 2018. Therefore, no deferred income tax expense or recovery has been recorded in earnings in the current period. The deferred tax recovery of $76 thousand for the period represents the premium paid by the subscribers of the flow-through common share offering for the tax benefits renounced.

Clearview has no current income taxes payable and has estimated tax pools available against income of $148.2 million, including non-capital tax loss carry-forwards of $53.5 million which will expire over the years 2026 to 2038. 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, 2018, Clearview has claimed $6.6 million against the successor pools.

The Company's tax pools as at December 31, 2018 are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	129	15,496	15,625
Canadian development expense (CDE)	30	9,431	17,464	26,895
Canadian oil and gas property expense (COGPE)	10	29,608	8,942	38,550
Foreign resource expenses	10	5,501	-	5,501
Undepreciated capital cost (UCC)	25	7,992	-	7,992
Share issue costs	20	159	-	159
Non-capital losses carry forward	100	53,171	-	53,171
Total tax pools		105,991	41,902	147,893

[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 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Cash flow provided by (used in) operating activities	1,312	525	150	1,088	4,337	(75)
Add back (deduct)						
Decommissioning expenditures	59	101	(42)	59	223	(74)
Change in non-cash working capital	(860)	563	(253)	705	(881)	180
Adjusted funds flow (1)	511	1,189	(57)	1,852	3,679	(50)

(1) See non-GAAP measures

Adjusted funds flow decreased 57% for the three months ended December 31, 2018, primarily due to the significant drop in realized oil and natural gas liquids prices.

For the period ended December 31, 2018 cash flow from operations was $1.1 million compared to $4.3 million for the year ended March 31, 2018. The decrease of 75% was due to lower revenues from lower prices in the last quarter of the year and one quarter less of operations.

For the period ended December 31, 2018 adjusted funds flow was $1.9 million compared to $3.7 million for the year ended March 31, 2018. The decrease of 50% was due to lower revenues from lower prices in the last quarter of the year and one quarter less of operations.

Net loss

	Three months ended			Periods ended		
	Dec. 31 2018	Dec. 31 2017	% Change	Dec. 31 2018	Mar. 31 2018	% Change
Net earnings (loss)	(2,083)	(2,435)	(14)	(4,832)	(8,460)	(43)
Per boe	(10.14)	(12.45)	(19)	(8.26)	(10.95)	(25)
Per share – basic	(0.20)	(0.29)	(31)	(0.48)	(1.00)	(52)
Per share – diluted	(0.20)	(0.29)	(31)	(0.48)	(1.00)	(52)

The Company sustained net losses of $2.1 million and $4.8 million for the three months and period ended December 31, 2018, respectively, compared to net losses of $2.4 million and $8.5 million for the comparative periods, respectively.

The decrease in the net loss for the period ended December 31, 2018 was primarily due to lower depletion and lower cash flow from operating activities, a reflection of there being one less quarter in the period ended December 31, 2018 versus the prior year.

Netback analysis

Barrel of oil equivalent ($/boe)	Three months ended Dec. 31 2018	Dec. 31 2017	% Positive (Negative)	Periods ended Dec. 31 2018	Mar. 31 2018	% Positive (Negative)
Realized sales price	22.36	26.83	(17)	27.82	26.30	6
Royalties	(1.72)	(2.91)	41	(3.39)	(2.97)	(14)
Processing income	0.50	1.03	(52)	0.80	1.05	(24)
Transportation	(1.42)	(1.29)	(10)	(1.32)	(1.39)	5
Operating	(15.83)	(15.72)	(1)	(15.69)	(14.69)	(7)
Operating netback (2)	3.89	7.94	(51)	8.22	8.30	(1)
Realized gain (loss) – commodity contracts	2.16	1.43	51	(1.29)	0.74	(274)
General and administrative	(2.18)	(2.18)	-	(2.51)	(2.87)	13
Transaction costs	-	-	-	(0.03)	(0.12)	75
Cash finance costs	(1.37)	(1.13)	(21)	(1.22)	(1.27)	4
Corporate netback (2)	2.50	6.06	(59)	3.17	4.78	(34)
Unrealized gain (loss) – commodity contracts	4.13	(6.10)	168	2.04	(1.51)	235
Stock based compensation	(1.77)	(1.16)	(53)	(1.19)	(1.22)	2
Depletion and depreciation	(11.01)	(10.76)	(2)	(10.54)	(10.72)	2
Impairment	-	-	-	-	(1.82)	100
E&E Expense	(0.29)	-	(100)	(0.10)	-	(100)-
Accretion	(0.28)	(0.49)	43	(0.56)	(0.46)	(22)
Loss on dispositions	(3.45)	-	(100)	(1.21)	-	(100)
Deferred income taxes	0.03	-	100	0.13	-	100
Net earnings (loss)	(10.14)	(12.45)	19	(8.26)	(10.95)	25

(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 year ended December 31, 2018 decreased 34% to $3.17 per boe compared to the prior year. The decrease is primarily due to realized losses on commodity contracts of $1.29 per boe versus realized gains on commodity contracts of $1.51 in the prior year.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sep 30 2017	Jun 30 2017	Mar 31 2017
Production								
Oil (bbl/d)	668	581	455	498	434	427	389	243
Natural gas liquids (bbl/d)	437	437	462	450	514	497	435	130
Natural gas (mcf/d)	6,745	6,537	6,764	7,175	7,085	7,576	7,006	2,223
Total (boe/d)	2,229	2,107	2,044	2,144	2,129	2,187	1,992	744
Financial								
Oil and natural gas sales	4,585	6,297	5,391	5,794	5,254	4,335	4,903	2,279
Adjusted funds flow (1)	511	749	592	429	1,189	824	1,237	223
Per share – basic	0.05	0.07	0.06	0.05	0.14	0.10	0.15	0.05
Per share – diluted	0.05	0.07	0.06	0.05	0.14	0.10	0.15	0.05
Net earnings (loss)	(2,083)	(1,000)	(1,749)	(3,879)	(2,435)	(1,864)	(282)	1,031
Per share – basic	(0.20)	(0.10)	(0.18)	(0.46)	(0.29)	(0.22)	(0.03)	0.21
Per share - diluted	(0.20)	(0.10)	(0.18)	(0.46)	(0.29)	(0.22)	(0.03)	0.21

(1) See non-GAAP measures.

Production increased on a quarter over quarter basis in the nine months ended December 31, 2018 with the successful light oil wells at Wilson Creek brought on stream in August and at Windfall brought on stream in November. Oil and natural gas sales and adjusted funds flow increased in the second quarter of the current period due to improved benchmark pricing for oil and natural gas liquids but decreased significantly in the last quarter of the current period due to weakening oil prices and a significant widening of light oil differentials in Canada. The increased loss in the last quarter of the current period was primarily due to a loss on the disposition of an asset of $0.7 million.

LIQUIDITY AND CAPITAL RESOURCES

The Company's liquidity was strengthened by the cash and working capital acquired through Bashaw Oil Corp., the proceeds on disposition from the asset held for sale as of March 31, 2018 and proceeds received from the issue of common shares and flow-through common shares to fund the Company's capital program. After the capital expenditures incurred in the second and last quarter and severe drop in commodity prices in the last few months of the year, net debt is $18.2 million at December 31, 2018, up from $14.2 million at March 31, 2018, with the components set out below:

As at	Dec. 31, 2018	Mar. 31, 2018
Trade and other receivables	2,358	2,711
Prepaid expenses and deposits	648	324
Assets held for sale	-	4,636
Bank debt	(16,553)	(16,250)
Accounts payable and accrued liabilities	(4,639)	(4,308)
Liabilities associated with assets held for sale	-	(1,267)
Net debt (1)	(18,186)	(14,154)

(1) See Non-GAAP measures.

Balance sheet strength and flexibility remain a priority through a challenging environment. 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 plans its capital program for 2019, continues to evaluate strategic acquisitions and prepares for the next review of its credit facility, to be completed by no later than June 30, 2019. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

At December 31, 2018, the Company had a demand revolving operating facility with ATB Financial with a limit of $21.0 million (March 31, 2018 - $26.0 million) of which $16.6 million (March 31, 2018 - $16.3 million) was drawn. The interest rate is prime plus 3% and the loan agreement requires monthly interest payments only. During the second quarter of the current period, the Company's lender reconfirmed the credit facility of $21.0 million. Additional changes made to the lending agreement at that time included revisions to the calculation of net debt to trailing cash flow ratio for the purposes of the credit facility's pricing grid. The net debt to trailing cash flow ratio is now calculated as current liabilities less current assets, excluding the fair value of financial instruments, divided by the most recent quarter's adjusted funds flow multiplied by four. The numerator now excludes the Company's long term decommissioning obligations.

The next scheduled review of the credit facility is no later than June 30, 2019. 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. The Company's credit facility is also a demand loan and as such the lender could demand repayment at any time. Since the facility is a demand loan it is classified as a current liability. Management is not aware of any indications the lender would demand repayment. The Company is current with all interest and fee payments and is compliant with all financial covenants, particularly the working capital covenant. The Company's ratio as per the working capital covenant is 1.6 to 1, well in excess of the minimum requirement of 1:1.

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 29, 2020 and acquired an additional office lease as part of the acquisition of Bashaw which expires April 30, 2020. The Company recovers a portion of the office costs from subleases to other corporations. These amounts are not reflected as recoveries in the table below.

The following is a summary of the Company's future minimum contractual obligations and commitments as of December 31, 2018.

	2019	2020	2021	2022	Thereafter
Bank debt	16,553	-	-	-	-
Accounts payable and accrued liabilities	4,639	-	-	-	-
Decommissioning obligations	-	-	-	-	22,645
Gas transportation	377	97	6	3	-
Office lease	312	133	-	-	-
Total	21,881	230	6	3	22,645

OFF-BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements. The commodity contracts for natural gas prices disclosed in the MD&A and are recorded at fair value as "fair value – commodity contracts" 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 23, 2019, the Company has 11,667,039 voting common shares outstanding and 1,108,667 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 $5.00.

Vesting period	Options - $4.50	Options - $5.00	Total
Currently vested	341,501	116,167	457,688
Vesting in the future in the three months ending:			
June 30, 2019	-	81,000	81,000
September 30, 2019	-	154,500	154,500
December 31, 2019	20,499	2,500	22,999
June 30, 2020	-	81,000	81,000
September 30, 2020	-	154,500	154,500
December 31, 2020	-	2,500	2,500
September 30, 2021	-	154,500	154,500
Total	362,000	746,667	1,108,667

For further details about the options refer to Note 10 to the financial statements as at and for the period ended December 31, 2018.

RELATED PARTY TRANSACTIONS

Related party transactions are disclosed in Note 14 of the financial statements as at and for the period ended December 31, 2018.

During the period ended December 31, 2018, $31 thousand (March 31, 2018 - $39 thousand) was recovered for shared office occupancy costs from Front Range Resources Ltd., a company with a director in common. Geological systems cost of $37 thousand (March 31, 2018 - $19 thousand) were paid to this same related party in the year ended December 31, 2018.

PROPOSED TRANSACTIONS

On February 22, 2019, subsequent to the fiscal year, the Company acquired producing oil and natural gas properties from a private oil and gas company (“Vendor”) producing approximately 300 boe/d for cash consideration of $0.6 million and the issuance of 1,357,194 common shares from treasury to the Vendor.

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, 2018 and March 31, 2018. Certain estimates and judgments are described in Note 2 to the audited financial statements for the periods ended December 31, 2018 and March 31, 2018. The following is a discussion of the accounting estimates that are critical in determining the Company’s financial results:

Property, plant and equipment

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

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

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

Decommissioning obligations

Decommissioning obligations are estimated for all wells and facilities in which the Company has an interest, regardless of whether reserves have been attributed to those assets by the Company's independent reserves evaluator. The Company estimates the future retirement date and likely current abandonment and reclamation costs for each well and facility based on current regulatory requirements, the regulator's estimates of such costs used to determine abandonment and reclamation costs and the Company's own experience, including historical costs incurred for abandonment or reclamation. To estimate future retirement costs, the Company applied a 2.0% 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 is usually a 10% discount rate.

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, 2018 and March 31, 2018. 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 market place.

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

During the period ended December 31, 2018, the Company adopted the following new accounting standards.

Revenue recognition

Effective April 1, 2018, the Company adopted IFRS 15, "Revenue from Contracts with Customers". IFRS 15 establishes a single, five-step model to be applied to all contracts with customers and two approaches to recognizing revenue; at a point in time or over time. The standard requires an entity to recognize revenue that reflects the transfer of goods and services for the amount it expects to receive when control has been transferred to the customer.

Clearview adopted the new standard on a modified retrospective basis, applying a practical expedient that provides transitional relief to contracts completed before April 1, 2018. As a result, no material changes have been made to the timing or amount of revenue recognized under the Company's previous revenue accounting policy as all good and services had been transferred during the comparative period. See Note 12 for the additional disclosure requirements of IFRS 15.

Financial instruments

IFRS 9, "Financial Instruments" replaces IAS 39, "Financial Instruments: Recognition and Measurement" and is effective for annual periods beginning on or after January 1, 2018. Clearview applied the new standard retrospectively as of April 1, 2018. The adoption of IFRS 9 did not result in any change in recognition or measurement of any of the Company's financial instruments on transition.

The new standard contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL"). The previous IAS 39 categories for financial assets of held to maturity, loans and receivables and available for sale have been eliminated. IFRS 9 bases the classification of financial assets on the business model for managing the financial asset and the characteristics of the contractual cash flows. There were no changes to measurement categories for financial liabilities.

IFRS 9 also introduces an expected credit loss model for evaluation impairment of financial assets. The credit loss model groups receivables based on similar credit risk characteristics. The expected credit loss model applies to the Company's trade and other receivables.

Accounting standards issued but not yet effective

Leases

IFRS 16, "Leases" will come into effect for fiscal years beginning on or after January 1, 2019, with earlier adoption permitted. IFRS 16 sets out principles for the recognition, measurement, presentation and disclosure of leases and will require lessees to recognize most lease assets and lease obligations on the balance sheet, effectively classifying all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements and may continue to be treated as an operating lease.

IFRS 16 is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS 16 as an adjustment to opening retained earnings and applies the standard prospectively. Clearview is currently assessing its outstanding leases and anticipates the adoption of IFRS 16 to increase the Company's assets and liabilities, increase depletion and depreciation expense, increase finance costs and reduce operating and general and administrative expenses. Cash payments associated with operating leases are currently presented within cash flows from operating activities. Under IFRS 16, the cash flows will be allocated between financing activities for the repayment of the principal obligation and operating activities for the financing expense portion. Clearview is currently reviewing its lease contracts with the effect on the Company's financial statements still being assessed.

INDUSTRY CONDITIONS AND RISKS

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

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

While the Board of Directors has the overall responsibility for the establishment and oversight of the Company's risk management framework, management has the responsibility to administer and monitor these risks. Refer to Note 15 of the audited financial statements for the year ended December 31, 2018 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 expenditures and abandonment, 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). 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