CLEARVIEW
RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

June 30, 2019

HIGHLIGHTS FOR THE THREE MONTHS ENDED JUNE 30, 2019

- On February 22, 2019, the Company closed the acquisition of light oil and natural gas assets in its west-central Alberta core area adding operated production;

- Increased Clearview's existing, light oil prone, undeveloped land base by 50% through the acquisition of assets;

- Incurred minimal capital expenditures of $0.8 million in the second quarter of 2019 to deploy excess adjusted funds flow of $0.5 million towards the reduction of net debt;

- Consistent with the strategy of the Company, increased oil production 56% in the three months ended June 30, 2019 to 709 barrels per day ("bbl/d"), up from 455 bbl/d in the comparative period of the prior year;

- Increased total production by 15% to 2,353 boe/d for the three months ended June 30, 2019 as a result of the continued strong production performance from the new wells brought on-stream in the prior year and the acquisition completed in the first quarter;

- Realized a sales price per boe for production for the three months ended June 30, 2019 which was 2% greater than the comparative quarter, primarily due to a greater oil sales mix;

- Reduced operating costs per boe by $0.34 to $14.46, a decrease of 2%, in the three months ended June 30, 2019 versus the comparative quarter;

- Increased the corporate netback in the three months ended June 30, 2019 to $5.98 per boe, an 89% improvement over the comparative quarter as a result of a $0.52 increase in revenue per boe and a $3.49 per boe reduction in realized hedging losses offset by an increase in all cash costs, net of processing income, of $1.20 per boe in the second quarter of 2019 versus the comparative period of 2018;

- Generated adjusted funds flow of $1.3 million in the first quarter, up 116% from the comparative quarter, as a result of a 15% increase in production and an 89% increase in the corporate netback per boe. Cash flow from operations was $0.8 million in the current quarter versus $0.3 million in the comparative quarter; and

- Reduced net debt by $1.9 million in the first six months of 2019, applying the excess of adjusted funds flow over capital expenditures of $1.5 million against working capital. At June 30, 2019, the Company's net debt to annualized six-month adjusted funds flow ratio was 2.4:1.

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The management discussion and analysis ("MD&A") is a review of the financial position and results of operations of the Company for the three and six months ended June 30, 2019 and 2018. The MD&A should be read in conjunction with the Company's unaudited condensed interim financial statements and accompanying notes for the three and six months ended June 30, 2019 and 2018 and the audited financial statements and accompanying notes for the periods ended December 31, 2018 and March 31, 2018. The unaudited condensed interim financial statements have been prepared in accordance with International Accounting Standard 34, Interim Financial Reporting. Unless otherwise noted, all dollar amounts in the tables are expressed in thousands of Canadian dollars ($000's), except per unit amounts. The MD&A has been prepared and approved by the Board of Directors as of August 21, 2019.

Refer to page 22 for information about non-GAAP measures, page 23 for information on forward-looking statements and page 24 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 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 increase focus and operating efficiencies

SELECTED ANNUAL INFORMATION

	Six months ended		Periods ended		
	June 30 2019	June 30 2018	Dec. 31 2018	Mar. 31 2018	Mar. 31 2017
Oil and natural gas sales	13,818	11,185	16,273	20,286	7,112
Adjusted funds flow (1)	3,344	1,021	1,852	3,679	(408)
Per share – basic	0.30	0.11	0.18	0.44	(0.10)
Per share – diluted	0.30	0.11	0.18	0.44	(0.10)
Cash flow from operations	2,438	2,209	1,088	4,337	(983)
Per share – basic	0.22	0.24	0.11	0.51	(0.25)
Per share - diluted	0.22	0.24	0.11	0.51	(0.25)
Net earnings (loss)	(1,112)	(5,628)	(4,832)	(8,460)	(1,896)
Per share – basic	(0.10)	(0.62)	(0.48)	(1.00)	(0.48)
Per share – diluted	(0.10)	(0.62)	(0.48)	(1.00)	(0.48)
Total assets	95,899	77,758	80,752	72,714	71,156
Total long term liabilities	31,043	22,291	22,645	18,873	15,607
Net debt (1)	16,327	12,066	18,186	14,154	14,604
Total capital expenditures – net (2)	1,485	928	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 and an impairment in the fiscal year ended March 31, 2018 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.

In the six months ended June 30, 2019, the Company's oil and natural gas sales increased to $13.8 million due to higher natural gas prices after the significant drop in prices in the fourth quarter of 2018, higher production from the acquisition of producing properties and increased total oil production for the Company from the new wells drilled in 2018. Adjusted funds flow was $3.3 million while cash flow from operations was $2.4 million for the six months ended June 30, 2019. Long term liabilities increased in the six months ended June 30, 2019 in connection with an acquisition of assets and net debt was reduced over the six months ended June 30, 2019 as adjusted funds flow in excess of capital expenditures was applied against working capital.

Business combinations

(a) Acquisition of assets

On February 22, 2019, Clearview acquired producing oil and gas assets and undeveloped land from a private oil and gas producer ("Private") for cash consideration of $0.6 million and the issuance to Private of 1,357,194 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 $110 thousand were recorded in earnings.

The acquisition of Private has been accounted for as a business combination. The allocation of the purchase price is preliminary and may be subject to change. The net assets have been allocated as follows:

Acquisition Date	February 22, 2019
Consideration	
Cash consideration	581
Share consideration (1,357,194 common shares)	8,482
Total consideration	9,063
Net assets at estimated fair value	
Working capital	87
Exploration and evaluation assets	182
Property, plant and equipment	10,737
Deferred income tax liabilities	(1,108)
Decommissioning obligations	(835)
Net assets	9,063

The fair value of property, plant and equipment has initially 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%.

(b) Acquisition of Bashaw Oil Corp.

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 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

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.

Capital expenditures

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Land	-	31	(100)	-	133	(100)
Drilling, completions, equipping	211	73	189	310	430	(28)
Facilities	200	167	20	293	271	8
Other	342	37	824	375	24	1,463
Capital invested	753	308	144	978	858	14
Disposition of properties	-	(3,367)	(100)	(4)	(3,367)	100
Net capital invested	753	(3,059)	-	974	(2,509)	-
Acquisition of properties	19	67	(72)	511	3,437	(85)
Total capital expenditures	772	(2,992)	-	1,485	928	60

The Company spent less than one-half of its adjusted funds flow on capital expenditures in the six months ended June 30, 2019 with the largest single component of the expenditures being the cash component of the acquisition of assets as discussed earlier. Other significant capital expenditures included workovers in several fields, replacement and upgrading of a generator and the overhaul of its facility at Windfall.

On January 4, 2018, the Company acquired working interests in producing oil and natural gas assets located in Central Alberta. The purchase price paid by the Company was $3.4 million after closing adjustments. The allocation of the purchase price, based on the estimated fair value of the assets and liabilities acquired, was as follows:

Net assets and liabilities at estimated fair values:	January 4, 2018
Property, plant and equipment	3,464
Exploration and evaluation (see Note 6)	283
Decommissioning obligations (see Note 9)	(377)
Cash consideration – net of closing adjustments	3,370

Production

Production is summarized in the following table:

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Oil – bbl/d	709	455	56	738	476	55
Natural gas liquids – bbl/d	452	462	(2)	462	456	1
Total liquids – bbl/d	1,161	917	27	1,200	932	29
Natural gas – mcf/d	7,153	6,764	6	7,398	6,969	6
Total – boe/d	2,353	2,044	15	2,434	2,094	16

Production for the three months ended June 30, 2019 increased by 15% over the comparative period due to two highly successful new light oil wells brought on production in the second half of the prior fiscal year and the acquisition of assets in the first quarter of the current year. With a focus on acquiring and drilling light oil opportunities, oil production increased 56% and 55% for the three and six months ended June 30, 2019, respectively, versus the comparative periods. For the three months ended June 30, 2019 natural gas liquids, generally associated with natural gas production, decreased by 2% while natural gas production increased by 6%. The increase in natural gas production is primarily from solution gas produced with the two new light oil wells brought on stream in the prior fiscal year.

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

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Wilson Creek	413	373	11	485	384	26
Northville	667	789	(15)	723	803	(10)
Pembina	247	242	2	227	243	(7)
Caribou	162	177	(8)	158	173	(9)
Windfall	339	144	135	398	130	206
Total – boe/d	1,828	1,725	6	1,991	1,733	15
% of total production	78%	84%	(7)	82%	83%	(1)

During the three months ended June 30, 2019, the Company experienced turnarounds by operators of processing facilities affecting production at Windfall and Wilson Creek. The growth in production in Wilson Creek and Windfall is a result of the wells drilled in the second half of the prior year.

Clearview's production portfolio for the three months ended June 30, 2019 was weighted 30% to oil, 19% to natural gas liquids and 51% to natural gas. For the three months ended June 30, 2018 the production mix was weighted 22% to oil, 23% to natural gas liquids and 55% 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.

Benchmark prices and economic parameters

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	59.84	67.88	(12)	57.35	65.38	(12)
Oil – Edmonton Par ($/bbl)	73.67	80.62	(9)	70.06	76.38	(8)
Differential – Light oil ($/bbl) (1)	6.36	6.98	(9)	6.41	7.14	(10)
NGLs - Pentane ($/bbl)	73.73	86.44	(15)	71.18	83.37	(15)
NGLs – Butane ($/bbl)	24.43	41.15	(41)	15.17	44.77	(66)
NGLs – Propane ($/bbl)	12.31	24.67	(50)	14.35	28.84	(50)
Natural gas – AECO ($/mcf)	1.02	1.18	(14)	1.82	1.63	12
Exchange rate – US$/Cdn$	0.7478	0.7748	(3)	0.7500	0.7828	(4)

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

The refiners' posted prices for Canadian crude oils are influenced by the WTI reference price, transportation capacity and costs, US$/Cdn$ exchange rates and the supply/demand situation of particular crude oil quality streams during the period. Benchmark oil prices had begun recovering in the six months ended June 30, 2019 from the significant drop in prices in the fourth quarter of 2018. WTI and Edmonton Par prices were still lower by 12% and 8%, respectively, in the six months ended June 30, 2019 versus the comparative period of 2018. During the second quarter of 2019, Edmonton Par prices were boosted by a strengthening WTI price, a weakening Canadian dollar relative to the US dollar and a reasonably consistent light oil differential relative to the first quarter of 2019.

Propane prices averaged $12.31 and $14.35 per barrel for the three and six months ended June 30, 2019, respectively, a decrease of 50% versus the comparative periods. Propane prices have been affected by an oversupply of propane and low demand through the winter for heating purposes due to the warm winter other than the month of February 2019.

Butane prices averaged $24.43 per barrel for the three months ended June 30, 2019, a decrease of 41% versus the comparative quarter of 2018. For the six months ended June 30, 2019, butane prices averaged $15.17 per barrel, a decrease of 66% versus the comparative period of 2018. Butane prices have declined significantly due to an oversupply of butane in Canada associated with the growth in liquids rich natural gas production in western Canada and less demand for butane as a diluent for heavier crudes.

Pentane prices averaged $73.73 and $71.18 per barrel for the three and six months ended June 30, 2019, respectively, a decrease of 15% versus the comparative periods of 2018. The decrease in pentane prices is consistent with the decrease in WTI over the same periods of 12%.

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 $1.02 per mcf for the three months ended June 30, 2019, a decrease of 14% as compared to the three months ended June 30, 2018 due to lower demand as winter demand comes to an end.

Realized sales prices

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Oil – $/bbl	69.12	73.71	(6)	65.69	68.50	(4)
NGLs – $/bbl	26.19	37.12	(29)	29.58	37.86	(22)
Natural gas – $/mcf	1.20	1.27	(6)	1.92	1.71	12
Total – $/boe	29.51	28.99	2	31.37	29.52	6

Realized prices primarily vary from the benchmark prices due to quality differences including differences for density and sulphur content. The differential can also vary considerably from quarter to quarter. During the three months ended June 30, 2019, the Company's realized oil prices were lower by 6% than the comparative quarter and lower by 4% for the first six months of the year as compared to the same period in 2018. The decreases in realized oil prices are consistent with the decreases in Edmonton Par pricing partially offset by the Company's increased mix of light oil production.

Natural gas liquids prices were lower by 29% for the three months ended June 30, 2019 versus the comparative quarter of 2018. This decrease was due to lower benchmark propane, butane and pentane prices and contract renewal terms for marketing of butane beginning April 1, 2019.

The Company's realized price for natural gas was lower by 6% for the three months ended June 30, 2019. This compares to a 14% decrease in the benchmark AECO price over the same period. For the six months ended June 30, 2019, the Company's realized gas price increased by 12% versus the comparative period, consistent with the increase in AECO over the same period. The Company's realized natural gas price is influenced by its Windfall natural gas production sold on the Alliance pipeline at the ATP price and a price adjustment for the heating content of this production.

On a boe basis, the Company's realized price was 2% and 6% higher for the three and six months ended June 30, 2019, respectively, than the comparative periods, primarily due to the growth in light oil production as discussed earlier.

Revenues

Oil and natural gas sales

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Oil	4,457	3,053	46	8,776	5,907	49
Natural gas liquids	1,077	1,557	(31)	2,476	3,123	(21)
Total liquids	5,534	4,610	20	11,252	9,030	25
Natural gas	784	781	-	2,566	2,155	19
Total sales	6,318	5,391	17	13,818	11,185	24
Per boe	29.51	28.99	2	31.37	29.52	6

Crude oil sales increased 46% in the three months ended June 30, 2019, versus the comparative period, due to an increase in oil production volumes of 56% from acquisitions and successful drilling partially offset by a 6% decrease in realized oil prices.

Natural gas liquids revenues were lower by 31% in the quarter ended June 30, 2019, versus the comparative quarter, as production was lower by 2% and natural gas liquids prices were lower by 29%.

Natural gas revenues were unchanged in the three months ended June 30, 2019, as compared to the same period of 2018, due to higher production volumes of 6% offset by a 6% decrease in the realized natural gas price.

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 was $0.3 million for the six months ended June 30, 2019, a 20% decrease from the comparative quarter. The decrease primarily reflects the streamlining of facilities in the field resulting in the elimination of processing income at certain facilities.

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Processing income	158	162	(2)	323	403	(20)
Per boe	0.74	0.87	(15)	0.73	1.06	(31)

Risk management activities

Clearview enters into 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 commodity contracts held by the Company that were outstanding as of June 30, 2019:

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
March 1, 2019	December 31, 2019	GJ/day	1,000	AECO 5A - Physical	$1.51
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
May 1, 2019	December 31, 2019	Bbl/day	150	WTI/Cdn - Financial	$87.00
May 1, 2019	December 31, 2019	Bbl/day	150	Differential - Financial	$10.80

The fair value of the financial contracts outstanding as at June 30, 2019 is estimated to be an asset of $0.4 million. At December 31, 2018 the fair value of the financial contracts outstanding was an asset of $0.1 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.

The change in the mark to market value during the three months ended June 30, 2019 resulted in an unrealized gain of $0.3 million as compared to an unrealized loss of $0.3 million for the comparative period. The change in the mark to market value during the six months ended June 30, 2019 resulted in an unrealized gain of $0.3 million as compared to an unrealized loss of $0.7 million for the comparative period.

The realized gain for the three months ended June 30, 2019 was $0.1 million versus a realized loss of $0.6 million for the comparative period. For the six months ended June 30, 2019, the realized loss was $0.1 million versus a realized loss of $0.9 million for the comparative period.

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			Six months ended		
Amount	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Crown – oil	339	314	8	611	598	2
Crown – natural gas liquids	324	447	(28)	669	853	(22)
Crown – natural gas	65	36	81	157	174	(10)
Gas cost allowance	(383)	(451)	(15)	(800)	(788)	2
Total Crown	345	346	-	637	837	(24)
Freehold	316	151	109	421	293	44
Gross over-riding	144	148	(3)	542	306	77
Total royalties	805	645	25	1,600	1,436	11
Per boe	3.76	3.47	8	3.63	3.79	(4)

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.

Royalty Rate	Three months ended June 30 2019	June 30 2018	% Change	Six months ended June 30 2019	June 30 2018	% Change
Total Crown	5.5%	6.4%	(14)	4.6%	7.5%	(39)
Freehold	5.0%	2.8%	79	3.0%	2.6%	15
Gross over-riding	2.3%	2.8%	(18)	3.9%	2.7%	44
Total royalties	12.8%	12.0%	7	11.5%	12.8%	(10)

The overall royalty burden for the three months ended June 30, 2019 increased by 7% to a rate of 12.8% versus 12.0% for the comparative quarter of 2018. Crown royalty rates in the three months ended June 30, 2019 were lower by 14% due to the lower royalty rates of 5% associated with the new light oil production from drilling and the reduced royalty rates for crude oil and natural gas liquids due to lower prices for all products as discussed earlier. Freehold royalties increased by 79% in the second quarter of 2019 primarily as a result of the reclassification of a prior period adjustment of $58 thousand and a 30% royalty rate on an acquired property. Gross over-riding royalties decreased by 18% in the three months ended June 30, 2019 due to lower prices for all products and the reclassification of $58 thousand from gross over-riding royalties to freehold royalties.

For the six months ended June 30, 2019, the overall royalty burden of the Company decreased by 10%. This decrease is primarily related to lower Crown royalty rates of 5% associated with the new light oil production from drilling and the reduced royalty rates for crude oil and natural gas liquids due to lower prices for all products as discussed earlier. Gross over-riding royalties increased due to higher natural gas prices, the lands on which new wells were drilled being encumbered by new over-riding royalties and a prior period adjustment related to an over-riding royalty from several years ago.

Transportation expenses

	Three months ended June 30 2019	June 30 2018	% Change	Six months ended June 30 2019	June 30 2018	% Change
Transportation costs	395	267	48	768	577	33
Per boe	1.83	1.43	28	1.74	1.52	14

Transportation expenses include trucking costs for delivery of the Company's oil production to receipt terminals and third-party pipeline tariffs to deliver natural gas production to the purchasers at the main market hubs. Transportation expense increased 48% and 33% in the three and six months ended June 30, 2019, respectively, versus the comparative period, due to higher production volumes of approximately 15% and the increased cost of more loads to truck the Company's oil production due to restricted load capacities during a prolonged period of road bans.

Operating expenses

	Three months ended June 30 2019	June 30 2018	% Change	Six months ended June 30 2019	June 30 2018	% Change
Operating costs	3,092	2,751	12	6,396	5,707	12
Per boe	14.46	14.80	(2)	14.52	15.06	(4)

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 June 30, 2019 were $14.46 per boe, lower by 2% than the comparative period, at $14.80 per boe. The decrease reflects a 15% increase in production offset by increased costs of 12%, primarily from the acquisition of assets in the first quarter of this year.

Operating costs for the six months ended June 30, 2019 were $14.52 per boe, lower by 4% than the comparative period, at $15.06 per boe. The decrease reflects a 16% increase in production offset by increased costs of 12%, primarily from the acquisition of assets in the first quarter of this year.

General and administrative expenses

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Gross costs	762	573	33	1,357	1,542	(12)
Overhead recoveries	(63)	(60)	5	(120)	(129)	(7)
Total G&A expenses	699	513	36	1,237	1,413	(12)
Per boe	3.26	2.76	18	2.81	3.73	(25)

For the three months ended June 30, 2019, general and administrative costs, net of recoveries, increased 36% versus the comparative period. The increase in the quarter is due to additional compensation pursuant to the Company's employee performance plan. General and administrative costs, net of recoveries, decreased 12% in the six months ended June 30, 2019 versus the comparative period. This decrease is primarily due to termination payments to several officers and employees of the Company being included in the comparative period.

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.

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Stock based compensation	192	84	129	542	308	76
Per boe	0.90	0.45	100	1.23	0.81	52

Stock based compensation expense for the three and six months ended June 30, 2019 was higher by 129% and 76%, respectively, versus the comparative periods. The increase in expense is primarily due to options granted to a director and numerous employees in the second quarter of the prior fiscal year.

Depletion, depreciation and impairment

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Depletion	2,564	1,894	35	5,142	4,013	28
Depreciation	2	2	-	4	9	(56)
Impairment	-	-	-	-	1,404	(100)
Total	2,566	1,896	35	5,146	5,426	(5)
Per boe – depletion	11.98	10.18	18	11.67	10.61	10
Per boe - depreciation	0.01	0.01	-	0.01	0.04	(75)
Per boe - impairment	-	-	-	-	3.71	(100)
Total	11.99	10.19	18	11.68	14.32	(18)

The Company calculates depletion on property, plant and equipment using the unit-of-production method based on proved plus probable reserves. Depreciation is calculated based on the useful lives of office equipment and furniture. The increase in depletion of 18% for the three months ended June 30, 2019 versus the comparative period is due to greater production volumes and a higher depletion rate. Production increased 15% and the depletion rate increased 18%.

For the six months ended June 30, 2019, depletion increased 28% as compared to the six months ended June 30, 2018. The increase is due to a 17% increase in production and a 10% increase in the depletion rate.

Transaction costs

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Transaction costs	25	16	56	110	112	(2)
Per boe	0.12	0.09	33	0.25	0.30	(17)

Transactions costs per boe for the three months ended June 30, 2019 were higher by 33% as compared to the three months ended June 30, 2018. The transaction costs relate to different business combinations as discussed earlier. Transactions costs will vary according to the nature and timing of the transactions undertaken.

Finance costs

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Interest on bank debt	271	217	25	567	455	25
Credit facility fees and costs	20	-	100	50	8	525
Cash finance costs	291	217	34	617	463	33
Accretion expense (1)	78	107	(27)	177	203	(13)
Total finance costs	369	324	14	794	666	19
Per boe – cash finance costs	1.36	1.17	16	1.40	1.22	15
Per boe – accretion expense	0.36	0.58	(38)	0.40	0.54	(26)

(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 six months ended June 30, 2019 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 in the prior fiscal year.

The interest rate on prime based borrowings under the credit facility has increased over the past 18 months as follows:

- 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 six months ended June 30, 2019 was 6.95%.

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 6.1% during the six months ended June 30, 2019.

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.

Income taxes

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Deferred income tax recovery	606	-	100	1,108	-	100
Per boe	2.83	-	100	2.52	-	100

The Company has concluded that it is not probable that the deferred income tax assets associated with temporary timing differences will be realized. As a result, this asset has not been recognized at June 30, 2019. However, as a result of the deferred tax liability created on the acquisition of assets, a deferred tax recovery of $1.1 million has been recorded in earnings in the six months ended June 30, 2019.

Adjusted funds flow

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

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Cash flow provided by (used in) operating activities	847	277	206	2,438	2,209	10
Add back (deduct)						
Decommissioning expenditures	-	-	-	-	122	(100)
Change in non-cash working capital	433	315	37	906	(1,310)	-
Adjusted funds flow (1)	1,280	592	116	3,344	1,021	228

(1) See non-GAAP measures

Adjusted funds flow increased 116% for the three months ended June 30, 2019, to $1.3 million. The increase is primarily due to increased revenues from greater sales of oil production.

For the three months ended June 30, 2019 cash flow from operations was $0.8 million compared to $0.3 million for the three months ended June 30, 2018. The increase of 206% was primarily due to an increase in adjusted funds flow less a $0.1 million use of working capital.

Net loss

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Change	June 30 2019	June 30 2018	% Change
Net earnings (loss)	(658)	(1,749)	(62)	(1,112)	(5,628)	(80)
Per boe	(3.07)	(9.41)	(67)	(2.52)	(14.85)	(83)
Per share – basic	(0.06)	(0.18)	(67)	(0.10)	(0.62)	(84)
Per share – diluted	(0.06)	(0.18)	(67)	(0.10)	(0.62)	(84)

The Company sustained a net loss of $0.7 million for the three months ended June 30, 2019 compared to a net loss of $1.7 million for the comparative period.

The decrease in the net loss for the three months ended June 30, 2019 was primarily due to higher revenues, lower realized and unrealized losses on commodity contracts and a deferred income tax recovery, all of which was partially offset by higher depletion due to higher production.

Netback analysis

	Three months ended			Six months ended		
	June 30 2019	June 30 2018	% Positive (Negative)	June 30 2019	June 30 2018	% Positive (Negative)
Realized sales price	29.51	28.99	2	31.37	29.52	6
Royalties	(3.76)	(3.47)	(8)	(3.63)	(3.79)	4
Processing income	0.74	0.87	(15)	0.73	1.06	(31)
Transportation	(1.83)	(1.43)	(28)	(1.74)	(1.52)	(14)
Operating	(14.46)	(14.80)	2	(14.52)	(15.06)	4
Operating netback (2)	10.20	10.16	-	12.21	10.21	20
Realized gain (loss) – commodity contracts	0.52	(2.97)	118	(0.16)	(2.27)	93
General and administrative	(3.26)	(2.76)	(18)	(2.81)	(3.73)	25
Transaction costs	(0.12)	(0.09)	(33)	(0.25)	(0.30)	17
Cash finance costs	(1.36)	(1.17)	(16)	(1.40)	(1.22)	(15)
Corporate netback (2)	5.98	3.17	89	7.59	2.69	182
Unrealized gain (loss) – commodity contracts	1.36	(1.36)	200	0.68	(1.88)	136
Stock based compensation	(0.90)	(0.45)	(100)	(1.23)	(0.81)	(52)
Depletion and depreciation	(11.99)	(10.19)	(18)	(11.68)	(10.65)	(10)
Impairment	-	-	-	-	(3.71)	100
Accretion	(0.36)	(0.58)	38	(0.40)	(0.54)	26
Deferred income taxes	2.83	-	100	2.52	-	100
Net earnings (loss)	(3.07)	(9.41)	67	(2.52)	(14.85)	83

(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 per boe for the three months ended June 30, 2019 increased 89% versus the comparative quarter. The increase is primarily due to increased revenue per boe and realized gains on commodity contracts versus losses in the comparative period.

For the six months ended June 30, 2019 the Company's corporate netback per boe increased 182% as compared to the same period of the prior year. The increase is primarily due to increased revenue, reduced losses on commodity contracts and lower general and administrative costs.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sep 30 2017
Production								
Oil (bbl/d)	709	768	668	581	455	498	434	427
Natural gas liquids (bbl/d)	452	473	437	437	462	450	514	497
Natural gas (mcf/d)	7,153	7,646	6,745	6,537	6,764	7,175	7,085	7,576
Total (boe/d)	2,353	2,515	2,229	2,107	2,044	2,144	2,129	2,187
Financial								
Oil and natural gas sales	6,318	7,500	4,585	6,297	5,391	5,794	5,254	4,335
Adjusted funds flow (1)	1,280	2,064	511	749	592	429	1,189	824
Per share – basic	0.11	0.19	0.05	0.07	0.06	0.05	0.14	0.10
Per share – diluted	0.11	0.19	0.05	0.07	0.06	0.05	0.14	0.10
Net earnings (loss)	(658)	(454)	(2,083)	(1,000)	(1,749)	(3,879)	(2,435)	(1,864)
Per share – basic	(0.06)	(0.04)	(0.20)	(0.10)	(0.18)	(0.46)	(0.29)	(0.22)
Per share - diluted	(0.06)	(0.04)	(0.20)	(0.10)	(0.18)	(0.46)	(0.29)	(0.22)

(1) See non-GAAP measures.

Production decreased in the second quarter of 2019 compared to the previous quarter as a result of extended road bans from a wet spring which delayed bringing wells back on production and turnarounds conducted by operators of processing facilities in two of the Company's core fields. Revenues and adjusted funds flow were lower in the second quarter than the first quarter of 2019 due to lower production and lower natural gas, propane and butane prices. The net loss for the second quarter increased by $0.2 million as the decrease in revenue was partially offset by realized and unrealized gains on commodity contracts and lower costs.

LIQUIDITY AND CAPITAL RESOURCES

The Company's liquidity was strengthened in the six months ended June 30, 2019 as the capital expenditures incurred was less than one-half of the Company's adjusted funds flow for the period. As a result, net debt is $16.3 million at June 30, 2019, down from $18.2 million at December 31, 2018, with the components set out below:

As at	June 30, 2019	Dec. 31, 2018
Trade and other receivables	2,747	2,358
Prepaid expenses and deposits	955	648
Bank debt	(16,475)	(16,553)
Accounts payable and accrued liabilities	(3,554)	(4,639)
Net debt (1)	(16,327)	(18,186)

(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. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

At June 30, 2019, the Company had a demand revolving operating facility with ATB Financial with a limit of $21.0 million (December 31, 2018 - $21.0 million) of which $16.5 million (December 31, 2018 - $16.6 million) was drawn. The interest rate is prime plus 3% and the loan agreement requires monthly interest payments only.

Subsequent to the end of the quarter, the Company's lender completed its annual credit facility review and established a limit of $18.5 million. Documentation of this revised facility is expected to be completed over the next several weeks. 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 2.3 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 June 30, 2019.

	2019	2020	2021	2022	Thereafter
Bank debt	16,475	-	-	-	-
Accounts payable and accrued liabilities	3,554	-	-	-	-
Decommissioning obligations	-	-	-	-	31,043
Gas transportation	186	97	6	3	-
Office lease	156	133	-	-	-
Total	20,371	230	6	3	31,403

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 August 21, 2019, the Company has 11,671,387 voting common shares outstanding and 1,061,167 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	324,001	167,167	491,168
Vesting in the future in the three months ending:			
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	344,500	716,667	1,061,167

For further details about the options refer to Note 9 to the financial statements as at and for the three and six months ended June 30, 2019.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's unaudited condensed interim 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 has varied from 10%-13% discount rate.

Stock based compensation

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 six months ended June 30, 2019, the Company adopted the following new accounting standard.

Leases

Effective January 1, 2019, the Company adopted IFRS 16 which replaced IAS 17 "*Leases*" and IFRIC 4 "*Determining Whether an Arrangement Contains a Lease*". IFRS 16 introduces a single, on-balance sheet accounting model for lessees which requires the recognition of a right of use asset and a lease liability on the balance sheet for most leases. Certain short-term leases (less than 12 months) and leases of low-value assets can be exempt from the balance sheet recognition requirements and will continue to be expensed through earnings on a straight-line basis over the term of the contract.

The Company adopted IFRS 16 using the modified retrospective approach. Under this method of adoption, the right of use assets recognized were measured at amounts equal to the present value of the lease obligations. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effective of IFRS 16 as an adjustment to opening retained earnings and applies the standard prospectively. Clearview elected to not apply lease accounting to certain leases for which the lease term ends within 12 months or is of low value as of the date of adoption.

The Company did an evaluation of all its contracts and it was determined there is no material affect as a result of adopting IFRS 16 and as such no adjustment or additional disclosures have been made. The Company has adopted an accounting policy for leases as follows:

Leases
Leases or contractual obligations are capitalized as right of use assets with a corresponding right of use lease obligation on the balance sheet calculated as the present value of future lease payments. The discount rate used to determine the present value of future lease payments is the interest rate implicit in the lease, or if that rate cannot be readily determined, the Company's incremental borrowing

rate. Certain lease payments will continue to be expensed through earnings. These types of leases would be short-term leases equal to or less than twelve months, leases for the purpose of oil and gas extraction or leases whereby the underlying asset is of low value.

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 condensed interim financial statements for the three and six months ended June 30, 2019 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

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