CLEARVIEW RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

June 30, 2017

HIGHLIGHTS FOR THE PERIOD APRIL 1, 2017 TO AUGUST 24, 2017

- *Production*
  - *Q1 2018 production averaged 1,992 boe/d compared to 744 boe/d for Q4 2017 and 695 boe/d for Q1 2017, and*
  - *current production is approximately 2,100 boe/d with the increase the result of optimization projects on the oil and natural gas properties acquired in Q4 2017.*
- *Operating results*
  - *Q1 2018 cash flow from operations is $1,237 compared to $158 for Q4 2017 and $170 for Q1 2017 which on a per boe basis are $6.82, $2.36 and $2.69 respectively,*
  - *the nearly threefold increase in Q1 2018 netback over Q4 2017 was achieved despite a decline in realized oil and liquids prices of over 15%,*
  - *the hedging strategy contributed to the strong cash flow and netback generating $119 or $0.66/boe,*
  - *Q1 2018 production costs (net of processing fee revenue) are $13.18/boe compared to $15.77/boe for Q4 2017 and $15.41/boe for Q1 2017, and*
  - *Q1 2018 general and administrative costs are $2.95/boe compared to $7.15/boe for Q4 2017 and $3.59/boe for Q1 2017.*
- *Development*
  - *advanced drilling plans including:*
    - *attained two licenses to drill horizontal wells targeting Cardium zone (oil) in Wilson Creek,*
    - *progressed plans for the drilling of Glauconite wells (liquids rich natural gas) in Northville, and*
  - *drilling has otherwise been deferred until commodity prices support acceptable payouts and returns during the period of initial production rates.*
- *Acquisitions*
  - *the Company is well positioned to replicate the recent acquisition successes as continued low commodity prices generate favorable acquisition metrics on properties with existing production and low-risk development potential, and*
  - *management and the Board of Directors continue to evaluate potential acquisitions in the core West Central Alberta region.*
- *Administrative*
  - *moved to new office premises at 2400, 635-8th Ave SW, Calgary, Alberta with a three-year sub lease agreement and fixed gross rents at favorable rates,*
  - *integrated new personnel into the Company, currently employing 8 individuals full-time plus 3 part-time consultants, and*
  - *acquired and/or integrated land, accounting, personnel, payroll and other systems and policies typical of a junior producer.*

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OVERVIEW OF THE COMPANY

Clearview Resources Ltd. (the "Company") is an oil and natural gas producing company based in Calgary, Alberta. The Company is focused on the following objectives:

- to acquire long life, cash generating oil and natural gas properties with growth potential, and
- to maintain a low cost and a financially robust structure.

The Company's oil and natural gas properties are in Alberta with a core focus area in West Central Alberta:

Region - Alberta	Property	Primary production	Average WI	Operatorship	Acquired [1]
West Central	Northville	Liquids rich natural gas	86.7%	Yes	2017
	Pembina	Liquids rich natural gas	92.7%	Yes	2017
	Wilson Creek	Light oil and liquids rich natural gas	61.3%	Yes	2017[2]
	Lindale (Unit)	Light oil with associated natural gas and liquids	10.6%	No	2012
Other Central	Warburg (Unit)	Light oil	3.8%	No	2012
	Carstairs (Unit)	Liquids rich natural gas	17.0%	No	2012
	Crossfield (Unit)	Liquids rich natural gas	4.2%	No	2012
	Caroline (Unit)	Liquids rich natural gas	0.2%	No	2012
	East Crossfield (Unit)	Liquids rich natural gas	4.9%	No	2012
Northern	Caribou	Light oil	69.3%	Yes	2017
Southern	Bantry	Medium oil	40.0%	No	2011
	Carmangay	Light oil	20.1%	No	2011
	Miscellaneous	Various	Various	Mixed	2011

[1]fiscal year ended March 31

[2]smaller parcels also acquired in 2014 and 2015

GENERAL

This management discussion and analysis ("MD&A") of the Company for the three months ended June 30, 2017 contains financial highlights but does not contain the complete financial statements of the Company. It should be read in conjunction with the Company's unaudited, Condensed Interim Financial statements for the three months ended June 30, 2017 and the Audited Financial Statements for the year ended March 31, 2017 and the MD&A dated March 31, 2017. Refer to page 18 for information about non-IFRS measures used in the MD&A. All references to dollar amounts are in thousands of Canadian dollars ($000`s) except volumes, per unit amounts and if otherwise indicated. This MD&A includes events up to August 24, 2017. Additional information is available on SEDAR at www.sedar.com.

STRATEGY OF THE COMPANY

In fiscal 2017 the Company established a growth strategy of acquiring and growing focused, high quality core areas with significant development potential. The transformation was achieved in fiscal 2017 as summarized below:

- established the following metrics to achieve growth and serve as the basis for the management incentive plan:

Category	Metric	Threshold or Target
Valuation	Net asset value[1] per fully diluted share	15% growth
Operations	Recycle ratio[2]	1.6 or greater
Financial	Net debt to cash flow ratio	No greater than 2.0
	License liability rating ("LLR")	Greater than 2.0

[1]Future cash flows from proved plus probable reserves present valued at a discount rate of 10%.

[2] Operating netbacks for the period divided by finding, development and acquisition costs for the period.

- closed two strategic acquisitions of West Central Alberta oil and liquids rich natural gas properties, both with significant, low-risk devolvement potential and operatorship of most of the lands and wells:
  - February 2017 - Wilson Creek - $11,355 and
  - March 2017 – Northville, Pembina and Caribou - $20,100,
- closed three tranches of equity financing by issuing voting common shares:
  - August 2016 - $5,000 - 1,111,111 shares at $4.50 per share,
  - February 2017 - $5,200 – 1,040,051 shares at $5.00 per share, and
  - March 2017 - $15,625 – 3,187,922 shares at $5.00 per share,
- sold two non-core properties in October 2016 for cash proceeds totaling $2,010,
- arranged credit facilities totaling $26,000, and
- achieved the following metrics by April 1, 2017:
  - production - 2,000 boe/d,
  - total proved producing reserves - 5.1 mboe,
  - total proved reserves - 9.2 mmboe, and
  - total proved plus probable reserves -14.6 mmboe,
  - LLR - 3.13.

The acquired properties provide the following corporate strengths going forward:

- include operatorship of most of the land and wells,
- create a core area in West Central Alberta building on the Company's existing properties at Lindale and Wilson Creek,
- provide significant low risk development (both oil and natural gas) opportunities in multiple geological zones of some 70 gross (52 net) drilling locations of which 40 gross (30 net) were recognized by the independent reserve evaluators at March 31, 2017,
- enhance the Company's LLR to be in excess of 3 and
- provide strong lending values as evidenced the recent renewal of the Company's credit facility at $21,000 despite lower commodity prices.

The acquisition phase of the strategic transformation occurred in fiscal 2017. Integrating the acquired and legacy assets and the management team has been the focus of Q1 2018, along with planning for the development on the acquired properties.

Operations

Operations for the quarter ended June 30, 2017 include both of the acquisitions described above, the first full quarter for the combined production and operations.

Production is summarized in the following table:

	3 months ended June 30, 2017	3 months ended June 30, 2016	12 months ended March 31, 2017	12 months ended March 31, 2016
Oil and liquids – bbl/d	825	361	346	419
Natural gas – mcf/d	7,006	2,004	1,914	1,956
Total – boe/d	1,992	695	665	745

Q1 2018 production increased over prior periods due to the production from the Q4 2017 acquisitions which produced as follows in Q1 2018:

- Wilson Creek – 337 boe/d, and
- Northville, Pembina and Caribou – 1,101 boe/d.

There was also incremental production from two horizontal Cardium oil wells in the non-operated property at Lindale, also in West Central Alberta. Three (0.32 net) oil wells were drilled at Lindale in March 2017 of which two were also completed and equipped in March 2017. Lindale production for Q1 2018 averaged 108 boe/d compared to 82 boe/d in Q4 2017. The third well was completed in August 2017. Net capital costs for each of these wells was approximately $286. Total capital expenditures for the quarter ended June 30, 2017 were $278, comprised of $155 at Carmangay for gathering systems and facilities, $55 at Lindale related to the drilling program described above and some minor projects,

The Company's cash flows are analyzed in Table B on page 9. Q1 2018 generated operating netback (petroleum revenue plus processing fess less royalties, transportation and production expense) of $1,890 compared to $885 in Q4 2017 and $542 in Q1 2017. Q1 2018 is the first quarter to include the increased operating cash flows as a result of the properties acquired in Q4 2017. Cash flows from operations (operating netback less general, administrative and financing expense, plus or minus the gain or loss on hedge contracts) for Q1 2018 amounted to $1,237 compared to $170 in Q1 2017, again due to the increased scale of operations due to the acquisitions.

OUTLOOK

As of August 24, 2017, the Company is producing approximately 2,100 boe/d with the weighting being approximately 40% for oil + liquids and 60% for natural gas. Since closing the acquisitions in Q4 2017, the Company identified a number of low cost optimization projects in these assets. The increased production to approximately 2,100 boe/d at the current time is the result of implementing some of these projects with others to be implemented over the next few months. These projects are very economic even with the recent pullback in oil and natural gas prices.

The Company, as operator, intends to drill horizontal wells (working interests of 67% to 100%) on its Wilson Creek property targeting the Cardium formation (light oil) and which will cost an estimated $2,100 per gross well. First year gross production rates on each new well are estimated to average 125 boe/d. Further, the Company intends to drill horizontal wells (working interests of 40% to 100%) on its Pembina property targeting the Glauconite formation (liquids rich natural gas) which will cost an estimated $2,600 per gross well. First year gross production rates on each new well are estimated to average 260 boe/d.

The timing of the development depends on a number of factors, including availability of drilling rigs, weather and oil and natural gas price forecasts. The Company has "paused" any drilling pending an improvement in commodity prices. In the meantime, planning and analysis has continued including identifying proven drilling and completion advisory firms to guide those activities on behalf of the Company along with the upfront land and site preparation. The Company was recently issued two drilling licenses for horizontal wells (100% working interest) in Wilson Creek targeting Cardium oil. The licenses provide a one-year period in which to commence drilling the well.

The Company also participates in development opportunities proposed by operating partners, subject to satisfactory technical and economic analysis. Refer to the Operations section above which describes the recent drilling on the non-operated property at Lindale.

LIQUIDITY AND CAPITAL RESOURCES

The Company is in a strong liquidity position due to the net equity financing of $25,825 and the $2,010 proceeds from the sale of non-core assets in fiscal 2017. Net debt is $13,645 at June 30, 2017 down from $14,604 at March 31, 2017, with the components set out in Table A on Page 8. 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, 2017, the Company had a demand revolving operating facility with ATB Financial with a facility limit of $26,000 (March 31, 2017 - $26,000) of which $13,925 (March 31, 2017 - $14,250) was drawn. The facility was renewed effective August 24, 2017 with a facility limit of $21,000. The reduction from $26,000 was a function of lower commodity prices. The lower limit reduces commitment and standby fees from what would have been incurred otherwise while meeting the Company's liquidity needs currently and in the foreseeable future. The facility limit is also consistent with the target internal net debt to cash flow ratio of no greater than 2. The interest rate remains the same at prime plus 3% (currently 5.95%) and the loan agreement requires monthly interest payments only. The facility is subject to semiannual reviews with the next one due by January 31, 2018. The Company's credit facility is a demand loan and as such the lender could demand repayment at any time. Because 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 as the Company's draw on the loan is currently well below the facility cap, the Company is current with all interest and fee payments and is in compliance with all covenants, particularly the working capital covenant. The Company's ratio as per the working capital covenant is 4.65 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 managing its commodity price risk management program.

The Company enters into commodity price contracts for both oil and natural gas as the appropriate price opportunities present themselves with the following currently in place:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
February 1, 2017	January 31, 2018	bbls/d	50	NYMEX WTI CDN	$70.00
March 1, 2017	February 28, 2018	bbls/d	50	NYMEX WTI CDN	$70.52
April 1, 2017	March 31, 2018	bbls/d	50	NYMEX WTI CDN	$70.00
April 1, 2017	March 31, 2018	bbls/d	50	NYMEX WTI CDN	$70.25
March 1, 2017	February 28, 2018	GJ/d	700	CGPR AECO CDN	$2.70
April 1, 2017	March 31, 2018	GJ/d	1,200	CGPR AECO CDN	$2.77
May 1, 2017	October 31, 2017	GJ/d	950	CGPR AECO CDN	$2.735
June 1, 2017	December 31, 2017	GJ/d	950	CGPR AECO CDN	$2.90

As hedging is a key component of managing liquidity risk, management constantly monitors the market and additional hedges will be contracted as attractive pricing opportunities become available and if production increases from development or acquisitions.

Currently the Company has 8,437,866 voting common shares and options to acquire 722,000 voting common shares outstanding. The outstanding options have a 7-year life and vest as follows (based on respective exercise prices of $4.50 and $5.00):

Fiscal year of vesting	Options - $4.50	Options - $5.00	Total
2017	105,000	-	105,000
2018	132,333	-	132,333
2019	132,333	108,333	240,666
2020	27,334	108,333	135,667
2021	-	108,334	108,334
Total	397,000	325,000	722,000

For further details about the options refer to Note 6 to the Financial Statements as at and for the three months ended June 30, 2017.

TABLE A – EXTRACTS FROM THE FINANCIAL STATEMENTS

	June 30, 2017	March 31, 2017
Trade and other receivables	2,796	2,310
Deposits and prepaid expenses	603	228
Credit facility	(13,925)	(14,250)
Accounts payable and accrued liabilities	(3,119)	(2,892)
Net debt	(13,645)	(14,604)
Total assets	71,304	71,156
Current liabilities	17,044	17,142
Asset retirement obligation	15,895	15,607
Total shareholders' equity	38,365	38,407
Total liabilities and shareholders' equity	71,304	71,156

Three months ended June 30	2017	2016
Cash flow (used in) provided by operating activities	1,264	(203)
Cash invested in property, plant and equipment	(278)	(88)

TABLE B – OPERATING RESULTS FOR THE LAST EIGHT QUARTERS (¹Expenses settled with cash)

$000's except for production and per unit amounts	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016
Production – oil and liquids – bbls	75,055	33,636	26,374	33,339	32,880	34,823	42,760	35,205
Production – natural gas – mcf	637,543	200,058	144,448	171,672	182,367	175,931	199,612	186,026
Production - total boe	181,312	66,979	50,449	61,950	63,274	64,145	76,029	66,209
Production–oils & liquids- bbls/d	825	374	287	362	361	383	465	383
Production –natural gas - mcf/d	7,006	2,223	1,570	1,866	2,004	1,933	2,170	2,022
Production – boe/d	1,992	744	548	673	695	705	826	720
Oil and natural gas liquids revenue	3,112	1,674	1,225	1,341	1,303	1,091	1,456	1,672
Natural gas revenue	1,684	539	421	371	239	247	547	532
Total production revenue	4,796	2,213	1,646	1,711	1,542	1,338	2,003	2,204
Processing fee revenue	167	187	176	158	159	158	160	237
Total production and fee revenue	4,963	2,400	1,822	1,868	1,701	1,496	2,163	2,441
Royalties	(517)	(271)	(252)	(270)	(25)	(160)	(318)	(267)
Production and transportation	(2,556)	(1,244)	(1,363)	(1,225)	(1,134)	(1,163)	(1,437)	(1,488)
Operating net back	1,890	885	207	374	542	173	408	686
Realized hedge gain (loss)	119	19	(164)	(77)	(52)	11	-	-
General and administrative	(535)	(479)	(254)	(312)	(227)	(229)	(228)	(255)
Transaction	-	(117)	(319)	-	-	-	-	-
Interest and other financing costs (1)	(237)	(150)	(78)	(112)	(93)	(93)	(81)	(109)
Cash flow from (used in) operations	1,237	158	(608)	(127)	170	(138)	99	322
(Expenses)income not settled in cash–Table C	(1,519)	864	(421)	(587)	(1,289)	4,511	(7,585)	(8,953)
Net income (loss)	(282)	1,022	(1,029)	(714)	(1,119)	4,373	(7,486)	(8,631)
Net income (loss) per share - basic	(0.03)	0.21	(0.24)	(0.19)	(0.36)	1.41	(2.42)	(2.79)
Net income (loss) per share – fully diluted	(0.03)	0.19	(0.24)	(0.19)	(0.36)	1.41	(2.42)	(2.79)
Royalties as % of revenue	11%	12%	15%	16%	2%	12%	16%	12%
Per unit analysis - $ per unit								
Oil and liquids revenue- $/bbl	41.45	49.74	46.44	40.21	39.66	31.33	34.06	47.48
Natural gas revenue – $/mcf	2.64	2.70	2.92	2.16	1.31	1.40	2.74	2.86
Production revenue – $/boe	26.45	33.03	32.63	27.62	24.38	20.87	26.35	33.28
Processing fee revenue - $/boe	0.92	2.80	3.50	2.54	2.51	2.46	2.10	3.58
Royalties –$/boe	(2.85)	(4.05)	(5.00)	(4.35)	(0.40)	(2.50)	(4.18)	(4.04)
Production & transportation–$/boe	(14.10)	(18.57)	(27.02)	(19.77)	(17.92)	(18.13)	(18.90)	(22.47)
Operating netback – $/boe	10.42	13.21	4.11	6.04	8.57	2.70	5.37	10.35
Realized hedge gain (loss) - $/boe	0.66	0.29	(3.25)	(1.25)	(0.82)	0.17	-	-
General and administrative - $/boe	(2.95)	(7.15)	(5.03)	(5.04)	(3.59)	(3.58)	(2.99)	(3.85)
Transaction - $/boe	-	(1.75)	(6.32)	-	-	-	-	-
Interest & financing costs (1)-$/boe	(1.31)	(2.24)	(1.55)	(1.81)	(1.47)	(1.45)	(1.08)	(1.64)
Corporate netback – $/boe	6.82	2.36	(12.04)	(2.06)	2.69	(2.15)	1.30	4.86
Benchmark prices								
Natural gas–AECO 30-day spot $/mcf	2.79	2.72	3.11	2.36	1.42	1.83	2.48	2.92
Propane	19.21	28.81	25.08	12.23	9.96	7.14	9.89	2.37
Butane	38.68	44.53	42.35	33.20	32.39	29.34	36.45	30.63
Pentane	64.40	69.28	64.88	56.82	55.81	45.34	57.91	59.58
Oil - Edmonton light 40API - $/bbl	59.72	65.71	60.76	54.19	55.01	41.22	52.55	55.10
Oil-Hardisty Bow River 24.9API-$/ bbl	50.30	50.54	44.64	41.33	41.93	26.63	37.20	43.59
Medium oil differential - $/bbl	9.42	15.17	16.12	12.86	13.08	14.59	15.35	11.51

Table C – Income (expenses) not Settled in Cash

	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016
Stock based compensation	(240)	(203)	(155)	(81)	(296)	-	-	-
Depletion and depreciation	(1,904)	(947)	(513)	(645)	(659)	(606)	(845)	(917)
Impairment	-	(682)	-	-	-	5,200	(4,700)	(7,500)
Accretion–asset retirement	(84)	(40)	(26)	(33)	(34)	(36)	(40)	(36)
Gains -acquisitions or dispositions	-	2,700	99	-	-	-	-	-
Unrealized gain (loss) - hedges	709	36	175	172	(300)	(47)	-	-
Deferred tax	-	-	-	-	-	-	(2,000)	(500)
Total	(1,519)	864	(421)	(587)	(1,289)	4,511	(7,585)	(8,953)

EXPLANATION OF THE RESULTS OF OPERATIONS

Production revenue (refer to Table B on page 9)

Production

Average production for Q1 2018 (1,992 boe/d) is greater than Q4 2017 (744 boe/d) due to the production from the Q4 2017 acquisitions which contributed 1,438 boe/d to the current quarter's average. This also explains the increase over Q1 2017 (695 boe/d). There was also additional production from the Lindale oil property due to new drilling. Lindale produced 108 boe/d in Q1 2018 compared to 82 boe/d in Q4 2017 and 127 boe/d in Q1 2017.

Realized prices

Bantry produces medium gravity oil while all other oil production is light oil. Medium gravity oil realizes a lower price than light oil. The differential can vary considerably from quarter to quarter as shown in Table B on page 9.

Benchmark prices

Benchmark prices are provided in Tables B. The refiners' posted prices are influenced by the US$ WTI reference price, transportation costs, US$/C$ exchange rates and the supply/demand situation of particular crude oil quality streams during the period. Both oil and natural gas benchmark prices have been low throughout the eight quarters shown in Table C compared to prior years. Oil and liquids were particularly depressed in Q4 2016 while natural gas was particularly depressed in Q4 2016 and Q1 2017. The Q1 2018 differential between light and medium gravity oil was $9.42/bbl compared to the Q1 2017 differential of $13.08/bbl as shown in Table B. Benchmark and realized natural gas prices averaged considerably higher in Q1 2018 ($2.79/mcf) compared to Q1 2017 ($1.42/mcf).

Gains and losses on commodity contracts

The table on page 7 lists the financial commodity price contracts outstanding during Q1 2018 generating a realized gain on hedges of $119 (Q1 2016 – realized loss- $52) and unrealized gains of $709 (Q1 2017 – unrealized loss - $300).

Royalties (refer to Table B on page 9)

Royalties expense Periods ended June 30	3 months 2017	3 months 2016
Crown royalties - oil	93	23
Crown royalties – natural gas and liquids	518	70
Crown royalties - gas cost allowance	(337)	(207)
Freehold royalties – all commodities	128	99
Gross overriding royalties – all commodities[1]	115	40
Total	517	25
Royalties as a % of petroleum revenue	11%	2%
Oil production – bbls[2]	35,326	24,244
Liquids production – bbls[2]	39,389	8,613
Natural gas production – mcf[2]	632,273	182,491
Realized oil price - $/bbl[2]	55.22	44.95
Realized liquids price – $/bbl[2]	29.35	27.37
Realized natural gas price - $/mcf[2]	2.62	1.29

[1]Includes royalty to related party – see page 15.

[2]Excludes production from royalty interests.

Freehold and gross overriding royalties are generally at a fixed rate whereas crown royalties are on a sliding scale, i.e. decreasing with lower volumes and prices.

The Company reviews its entitlement to gas cost allowance at each reporting period end. 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. In Q1 2017 the Company received a refund for gas cost allowance credits of $141 related to prior periods, whereas for Q1 2018 there was a minor cost related to prior years of $10.

Production & transportation costs and processing fee revenue **(refer to Table B on page 9)**

Production and transportation expense Periods ended June 30	3 months Q1 2018	3 months Q1 2017
Transportation, gathering and processing	962	219
Workover, repairs and maintenance	323	189
Property taxes, lease rentals and regulatory fees	404	367
Other production costs	867	359
Total production and transportation costs	2,556	1,134
Processing fee revenue	(167)	(159)
Production & transportation expense less processing fees	2,389	975
Workover, repairs and maintenance – $/boe	1.78	2.99
All other costs above – $/boe	12.32	14.93
Total production & transportation costs –$ /boe	14.10	17.92
Processing fee revenue – $/boe	(0.92)	(2.51)
Production activity –$ /boe	13.18	15.41

Property, plant and equipment include working interests in natural gas processing facilities at Caroline, Carstairs, Crossfield and Wilson Creek. These facilities generate processing fee revenue for the Company which is analyzed in the above table along with the significant components of production and transportation costs.

The Company and its operating partners have focused on reducing production costs given the prolonged period of low oil and natural gas prices. However, significant components of operating an oil and natural gas property are essentially fixed, e.g. property taxes or lease rentals.

Q1 2018 production and transportation costs/boe ($14.10) are lower than Q1 2017 ($17.92) primarily due to the shift in production mix to a greater natural gas weighting of 59% in Q1 2018 compared to 48% in Q1 2017. Natural gas production cost per unit is expected to be lower than oil production cost per unit.

General and administrative expense (refer to Table B on page 9)

General and administrative expense Periods ended June 30	3 months Q1 2018	3 months Q1 2017
Personnel	325	133
Professional fees	61	41
Office and other	149	53
Total general and administrative	535	227
General and administrative – $/boe	2.95	3.59

Q1 2017 office and other costs include the costs of an upgrade of the Company's computer and information technology systems. Q1 2018 includes the costs of moving the office of $37. Personnel who are on a consulting fee basis are paid for actual time worked which can vary from quarter to quarter. Higher personnel costs were incurred in Q1 2018 compared to Q1 2017 due to employing 8 full time people which includes additional personnel (2 full time and 1 part-time) due to the growth through acquisitions in Q4 2017.

Interest and other financing costs (refer to Table B on page 9)

Interest and other financing costs Periods ended June 30	3 months Q1 2018	3 months Q1 2017
Accretion of asset retirement obligations	84	34
Interest on credit facility	197	73
Credit facility fees and costs	40	20
Finance expense for the year	321	127

Finance costs include interest and lender fees plus minor amounts for miscellaneous interest and penalties charged by vendors and taxing authorities. Increased rates for fees and interest (from 3.7% to 5.7%) on the credit facility became effective July 25, 2016. The rate increased 0.25% subsequent to June 30, 2017 due to the equivalent increase in the prime rate.

Stock based compensation (refer to Table C on page 10)

The Company has granted options to acquire voting common shares to directors, officers, employees and consultants as an equity based incentive and retention component of the compensation plan which was part of the corporate transformation over the 2017 fiscal year. The Board of Directors of the Company set the terms at the time of grant.

In May 2017, the Company granted options to acquire 325,000 voting common shares with an exercise price of $5.00 per share under option, expiring 7 years after the date of grant and vesting one third on each of the first, second and third anniversaries.

Stock based compensation expense for Q1 2018 amounted to $240 compared to $296 for Q1 2017. The latter included the amortization resulting from the immediate vesting of one-third of the options granted in Q1 2017. The following were used in the Black-Scholes calculations:

Three months ended June 30	2017	2016
Exercise price	$5.00	$4.50
Volatility	73%	73%
Expected option life	7.0 years	7.0 years
Dividend	$nil	$nil
Risk-free interest rate	0.5%	0.5%

The Company is not listed on a stock exchange. The exercise prices are based on recent issue prices for the voting common shares. The estimate of volatility is based on a sample of peer junior oil and natural gas producers listed on a Canadian stock exchange.

Depletion, depreciation and impairment (refer to Table D on page 10)

The Company reviews forecast prices and the quantity of proved plus probable reserves among other factors at each period end to identify indicators of possible impairment or recovery of impairment recorded in prior periods. Such indicators did not exist at June 30, 2017 or 2016 but did exist at March 31, 2017 and 2016 resulting in impairment for the fiscal 2017 of $738 (2016 - $7,000). Should prices or reserves materially change in the future, impairment tests would again be completed and impairment or impairment recoveries recorded accordingly.

Depletion expense is a function of volume produced as it is computed on a "unit of production" basis, using total proved plus probable reserves as the depletion base. The higher production increased the depletion expense to $1,904 ($10.96 per boe) in Q1 2018 compared to $659 ($10.95 per boe) in Q1 2017.

RELATED PARTY TRANSACTIONS

Related party transactions are disclosed in Note 9 of the financial statements as at June 30, 2017.

The Company has an agreement with the President and Chief Executive Officer which assigns a 1% gross over-riding royalty interest on all production or royalty revenue from oil or natural gas properties owned as at June 28, 2016. This royalty interest is attached to the property and transfers to the purchaser on the sale or other disposition of the property. Gross over-riding royalties (GORR) payable to the President and Chief Executive Officer, amounted to $15 in Q1 2018 compared to $14 in Q1 2017. Higher realized prices in Q1 2018 over Q1 2017 contributed to a higher royalty in the current period more than offsetting the impact of the sale of oil and natural gas assets in Q3 2017.

During Q1 2018 $6 (Q1 2017 - $7) was recovered for share occupancy costs from Front Range Resources Ltd., a company with a director in common. Geological systems costs of $19 (Year ended March 31, 2017 - $19) were paid to this same related party.

NEW ACCOUNTING POLICIES

No new or amended accounting standards or interpretations were adopted during Q1 2018.

Accounting standards issued but not yet effective

IFRS 15, "Revenue from Contracts with Customers establishes a single revenue recognition and measurement framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of good and services for the amount it expects to receive, when control is transferred to the purchaser. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. Management is currently assessing the potential impact of the adoption of this standard on the Company's financial statements.

IFRS 16, "Leases" was issued in January 2016 and requires 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 assists are exempt from the requirements. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers". Management is currently assessing the potential impact of the adoption of IFRS 16 on the Company's financial statements.

IFRS 9, "Financial Instruments", is intended to replace IAS 39, "Financial Instruments: Recognition and Measurement" and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. For financial liabilities designated at fair value through profit or loss, a company can recognize the portion of the change in fair value related to the change in the company's own credit risk through other comprehensive income rather than profit or loss. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. Management is currently assessing the potential impact act of the adoption of IFRS 9 on the Company's financial statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's 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 of these estimates over time. Revisions to accounting estimates are recognized in the year in which the estimates are revised and for any future years affected. A summary of the significant accounting policies used by the Company can be found in Note 2 to the March 31, 2017 Audited Financial Statements. 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.

Management reviewed its cash generating units following the acquisitions in the three months ended March 31, 2017 and in light of its current strategic and operating objectives. The review resulted in the combining of the two Southern Alberta CGU's as both prior CGU's are oil producing assets, the assets are geographically proximate and both are outside the Company's core operating area in West Central Alberta. Both CGU's were adjusted for impairment at March 31, 2017 and therefore carried at their respective recoverable amounts at March 31, 2017. Once combined as of April 1, 2017 the carrying value of the combined CGU is $7,446 being the sum of the recoverable amounts at March 31, 2017. The Company's CGU's are listed in the following table:

Cash generating units	
Fiscal 2018 and future years	Fiscal 2017 and prior years
Central Alberta Gas CGU	Central Alberta Gas CGU
Central Alberta Oil CGU	Central Alberta Oil CGU
Southern Alberta Oil CGU	Southern Alberta Oil CGU 1
	Southern Alberta Oil CGU 2

A discussion of the other critical accounting estimates can be found in the Management Discussion and Analysis at March 31, 2017. Additional information is available on SEDAR at www.sedar.

OFF BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements. The contracts on oil and natural gas prices have been disclosed above and are recorded at fair value on the balance sheet at each period end with gains or losses recorded through earnings.

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development and acquisition of oil and gas reserves involves a number of business risks inherent in the oil and gas industry which may impact the Company's results and several of which are beyond control of the Company. These business risks are operational, financial or regulatory in nature. These risks and the Company's approach to managing these issues are the same as disclosed in the Management's Discussion and Analysis for the year ended March 31, 2017. Refer to Note 11 of the Audited Financial Statements for the year ended March 31, 2017 for additional analysis of risks. The business of exploration, development, and acquisition of oil and gas reserves involves a number of financial, operational and regulatory risks inherent in the oil and gas industry which may impact the Company's results and several of which are beyond control of the Company.

Measures and Conversions

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	btu	Million British Thermal Units
boe	Barrels of oil equivalent	gj	Gigajoule
boe/d	Barrels of oil equivalent per day	Q	Quarter – three-month period
mboe	Thousand boe		

Boe - Barrel of oil equivalent is determined on the basis of 1 boe to 6 mcf of natural gas, 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

Non-IFRS 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 ("COGE Handbook") describes netback as "an operations indicator to assess operating priorities and evaluate smaller capital expenditures normally associated with field maintenance and improvement". The COGE Handbook 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 as a whole directly from the applicable amounts on the Statements of Operations in the financial statements being petroleum sales and processing fees less royalties, production and transportation costs. This amount divided by the applicable production volume (usually in boe's) provides a per unit amount.

Cash flow from operations (also referred to as corporate netback) is the operating netback plus or minus cash settled costs, in particular realized hedge gains (losses) and less general, administrative, interest and other financing costs. The same figures divided by the total production for the period represent net cash margin calculations for every barrel of oil equivalent sold.

Cash flow used in or from operations is reconciled to "cash provided by operating activities" on the Statement of Cash Flows in the Financial Statements by adjusting for the change in non-cash working capital and asset retirement expenditures (if any) as follows:

Three months ended June 30	2018	2017
Cash flow from operations per Table B (page 9)	1,237	170
Change in non-cash working capital for operating activities (1)	27	(373)
Cash (used in) provided by operating activities (1)	1,264	(203)

(1) Per Statements of Cash Flows – Financial Statements.

Net debt is computed for each period end and 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, cash flow from operations 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 junior producers in the oil and natural gas sector.

Forward-Looking Statements

The matters discussed in this 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.

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