CLEARVIEW RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

March 31, 2017

CLEARVIEW RESOURCES LTD.
HIGHLIGHTS FOR THE YEAR ENDED MARCH 31, 2017

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

- *closed two strategic acquisitions of oil and liquids rich natural gas properties, both in West Central Alberta and both with significant, low-risk development potential and operatorship of most of the lands and wells:*
    - *February 2017 - Wilson Creek - $11.4 million, and*
    - *March 2017 – Northville, Pembina and Caribou - $20.1 million,*
- *closed three tranches of equity financing by issuing voting common shares:*
    - *August 2016 - $5.0 million - 1,111,111 shares at $4.50 per share,*
    - *February 2017 - $5.2 million – 1,040,051 shares at $5.00 per share, and*
    - *March 2017 - $15.9 million – 3,187,922 shares at $5.00 per share,*
- *achieved growth:*
    - *Production:*
        - *more than tripled to 2,000 boe/d from 548 boe/d for Q3 2017,*
    - *Reserves:*
        - *more than doubled year-end total proved producing reserves to be 5.1 mmboe, from 2.2 mmboe at March 31, 2016,*
        - *grew year-end total proved reserves to 9.2 mmboe, 3.5 times the 2016 year-end amount of 2.6 mmboe and clearly demonstrating the low-risk development potential of the acquired properties, and*
        - *more than doubled year-end total proved plus probable reserves to be 14.6 mmboe, from 3.6 mmboe at March 31, 2016,*
    - *Licensee liability rating (LLR):*
        - *increased from 1.8 to currently 3.13,*
    - *Net asset value:*
        - *this growth in production and reserves significantly increases shareholder value,*
- *sold two non-core properties, effective October 1, 2016 for cash proceeds totaling $2.0 million, and*
- *arranged credit facilities totaling $26.0 million of which $14.3 million was drawn at March 31, 2017.*

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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 operate safely and efficiently and be financially robust.

All oil and natural gas properties are in Alberta, Canada 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	Carmangay	Light oil	20.1%	No	2011
	Bantry	Medium oil	40.0%	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 year ended March 31, 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 Audited Financial Statements for the year ended March 31, 2017 and the Form 51-101 F1 - Statement of Reserves Data and Other Oil and Gas Information, which are available on SEDAR at www.sedar.com. Refer to page 25 for information about non-IFRS measures used in the MD&A. This MD&A includes events up to July 26, 2017. Additional information is available on SEDAR at www.sedar.com.

All references to dollar amounts are in thousands of Canadian dollars ($000`s) except volumes, per unit amounts or if otherwise indicated

Summary of Activities for the Year Ended March 31, 2017

Strategy

The Company changed the strategic focus for the Company to a growth strategy from the former dividend paying model. The first phase was to seek one or more acquisitions meeting the following criteria:

- to be accretive on all key measurement criteria including the following per share metrics: production, cash flow, reserves and net assets,
- to provide low risk development opportunities in a timeframe consistent with the intention to create a liquidity event for the Company's shareholders within a 2 to 5 year time frame,
- to include operatorship as much as possible,
- to be focused in a core geological area,
- to maintain and preferably enhance the Company's Licensee Liability Rating ("LLR") which is a regulatory measure of the Company's ability to fund the eventual abandonment and reclamation costs once reserves are fully depleted, and
- to maintain a prudent net debt to cash flow ratio.

The following metrics were developed to guide operations (particularly acquisition and development decisions) and to provide the key metrics 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]	Median of a prescribed peer group
Financial	Debt to cash flow ratio	No greater than 2.5
	LLR	Greater than 1.5

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

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

Low oil and natural gas prices since 2015 has forced many public and private oil and natural gas companies to sell assets. The Company's new growth strategy took advantage of this environment as the Company acquired properties meeting all of the above criteria and thus completing the acquisition phase and positioning the Company very well for the second phase being low risk development, mostly in fill locations.

Each of the quarters of this fiscal year showed significant progress in executing on the strategy:

Q1 – three months ended June 30, 2016:

- growth strategy formally adopted by the Board of Directors,
- Lindsay Stollery named as Board Chair,
- two new directors added to the Board – David Vankka and Murry Scalf,
- granted options for 309,800 voting common shares to directors, officers, employees and consultants as an equity based incentive and retention component of the compensation plan; these options vest 1/3 immediately and 1/3 on each of the next two anniversaries, and
- negotiated a full-time employment agreement with CEO Greg Baum.

Q2 – three months ended September 30, 2016:

- commenced actively seeking accretive acquisitions consistent with the above criteria,
- raised equity of $5,000 as 1,111,111 voting common shares were issued, primarily to existing shareholders, applying the proceeds to reduce the draw on the Company's credit facility,
- process initiated to sell non-core assets, and
- expanded the management team to include an experienced professional geologist, Brett Abernethy.

Q3 – three months ended December 31, 2016:

- sold two non-core properties (Boundary Lake, BC and Spirit River, AB) effective October 1, 2016 for cash proceeds totaling $2,010, These properties averaged 77 boe/d in 2017 prior to sale, primarily oil,
- granted options for 82,000 voting common shares to directors, officers, employees and consultants in November 2016 which vest 1/3 on each of the first, second and third anniversaries, and
- completed the preliminary assessment and evaluation of many properties leading to two target acquisitions fitting the strategic profile and being marketed by companies in receivership.

Q4 – the three months ending March 31, 2017:

- completed the due diligence work (geological, engineering, reserve evaluation and legal) for the two target acquisitions,
- documented through the internal and external due diligence that the two acquisitions met the Company's acquisition criteria:
    - generate immediate operating cash flows from existing production of approximately 2,000 boe/d,
    - are accretive for the prescribed per share metrics: production, reserves, cash flow and net asset value,
    - 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,
    - 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,
    - enhance substantially the Company's LLR to 3.13, and
    - provide strong lending values approximating 50% of the acquisition costs,
- negotiated two Purchase and Sale Agreements for properties from companies in receivership:
    - Wilson Creek, West Central Alberta - $11,355, and
    - Northville and Pembina, West Central Alberta, and Caribou, Northern Alberta - $20,100,
- closed the first acquisition on February 7, 2017 and the second on March 27, 2017, both with an effective date of December 1, 2016,
- arranged revised loan facility agreements with ATB Financial with each of the acquisitions, resulting in a facility limit of $26,000 at March 31, 2017,
- concurrent with each acquisition issued voting common shares at $5.00 per share for aggregate proceeds of $21,140 (net $20,825) as follows:
    - with the first acquisition, issued 1,040,051 shares for gross proceeds of $5,200, and
    - with the second acquisition, issued 3,187,922 shares for gross proceeds of $15,940,
- with the acquisitions and subsequently, contracted commodity price contracts described and explained on page 8, and

- expanded the management team to include experienced professionals in land management and field operations, Renee Miles and Dima Shlyonchik, respectively, both formerly with one of the vendors and added Harold Pine as a Director.

The acquisition phase has now been substantially completed and planning for the development phase is well advanced.

Operations

Operations for the year ended March 31, 2017 include the acquired Wilson Creek assets for February and March of 2017 but do not include any production or operations of Northville, Pembina or Caribou as those were acquired in late March 2017.

The following summarizes production for the three and twelve-month periods ended March 31, 2017 and 2016:

Periods ended March 31	3 months Q4 2017	3 months Q4 2016	12 months 2017	12 months 2016
Oil and liquids – bbl/d	374	383	346	419
Natural gas – mcf/d	2,223	1,933	1,914	1,956
Total – boe/d	744	705	665	745

Q4 2017 production increased over Q4 2016 due to the production from the February 2017 acquisition which contributed 209 boe/d to the quarter's average of 744 boe/d more than offsetting the following:

- impact of the sale of two oil properties effective October 1, 2016 which produced 83 boe/d in Q4 2016 and averaged 77 boe/d in 2017 prior to sale, and
- lower production from the Lindale oil property which produced 108 boe/d in 2017 compared to 172 boe/d in fiscal 2016 due to normal production decline.

For 2017 and most prior years, development activity focused on drilling horizontal wells targeting Cardium oil 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. The completed wells commenced production in April 2017 initially averaging 200 (21 net) boe/d per well, being light oil with associated natural gas and liquids. The third well has not yet been completed but is expected to be on production in Q2 2018. Net capital costs for each of these wells was approximately $286. Total capital expenditures for the year ended March 31, 2017 were $934, comprised mostly of the costs related to the three Lindale wells in Q4 2017.

The Company's operating cash flows are analyzed in Tables B and C on pages 10 and 11. As the current year is the transition year for the Company's strategic shift to a growth model it was expected that cash flows in 2017 would be negatively impacted. Cash flow from operations in 2017 was $408 compared to cash flow used in operation in 2016 of $2,018. The change in cash flows was the result of the following:

- lower petroleum sales revenue by $1,197 primarily due to the lower production as non-core properties were sold and no development has occurred for over two years during the period of low oil and natural gas prices,

- unfavorable commodity hedge contracts outstanding during most of fiscal 2017, which realized losses of $274 while those in fiscal 2016 were favorable and realized gains of $304, and
- transaction costs in 2017 of $436 for professional fees for the geological, legal and reserve evaluation required in conducting due diligence on the target properties.
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OUTLOOK

Following the Q4 2017 acquisitions the Company was producing approximately 2,000 boe/d with the weighting being approximately 40% for oil + liquids and 60% for natural gas. A number of low cost optimization projects in the acquired assets have been identified. Some of those projects have been completed, resulting in current production of approximately 2,100 boe/d.

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 $2.1 million 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 $2.6 million 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 forecast oil and natural gas prices. In the meantime, planning and analysis has continued including identifying proven advisory firms to guide the drilling and completion on behalf of the Company along with the upfront land and site preparation. The Company was recently issued a drilling license for the first horizontal well (100% working interest in Wilson Creek targeting Cardium oil). The license provides 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 2017 drilling on the non-operated property at Lindale. The production from the 3 gross (0.32 net) wells drilled in March 2017 will benefit fiscal 2018.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity improved considerably in fiscal 2017 due to the $26,100 of equity financing, the $2,010 proceeds from the sale of non-core assets and the $26,000 facility limit with the Company's lender. At March 31, 2017 net debt is $14,604 (2016 - $11,315) with the components set out in Table A on Page 9. The Company carefully monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development. The Company targets a net debt to forward cash flow ratio to be no greater than 2.5 and preferably between 1 and 2, depending on the circumstances including the extent of recent acquisition or development activity. Forward cash flow is defined as revenue plus or minus gains or losses on commodity contracts and less royalties, production, transportation, general & administrative and finance expenses. Refer to "Non-IRS Measures on page 25)

At March 31, 2017, the Company had a demand revolving operating facility with ATB Financial with a facility limit of $26,000 (2016 - $18,000) of which $14,250 (2016 - $10,700) was drawn. The facility limit increased in Q4 2017 to $26,000 following the acquisitions of the two oil and natural gas properties as described in the Highlights section. The interest rate is prime plus 3% (currently 5.95%) and the loan agreement requires monthly interest payments only. The facility is subject to semiannual reviews.

The July 2017 annual review is in progress at the current time. 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 less than 60% of the facility limit, the Company is current with all interest and fee payments and is in compliance with all covenants.

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 in place as at July 26, 2017:

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

Management prepares an operating and capital budget for presentation to the Board and its credit facility lender. Management presents quarterly updates of the operating (including hedge contracts) and capital budgets (including potential acquisitions and dispositions) to the Board and adjustments to planned activities are made depending on projected cash flows and capital resources.

At July 26, 2017, the Company has 8,437,866 voting common shares and 722,000 options for 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 7 to the Audited Financial Statements as at and for the year ended March 31, 2017.

TABLE A – EXTRACTS FROM THE FINANCIAL STATEMENTS

EXTRACT FROM THE STATEMENTS OF FINANCIAL POSITION			
	March 31, 2017	March 31, 2016	March 31, 2015
Trade and other receivables	2,310	404	1,112
Deposits and prepaid expenses	228	238	245
Credit facility	(14,250)	(10,675)	(11,025)
Accounts payable and accrued liabilities	(2,892)	(1,282)	(2,249)
Net debt	(14,604)	(11,315)	(11,917)
Total assets	71,156	33,105	45,797
Current liabilities	17,142	12,004	13,274
Asset retirement obligation	15,607	7,358	7,435
Total shareholders' equity	38,407	13,743	25,088
Total liabilities and shareholders' equity	71,156	33,105	45,797

EXTRACTS FROM THE STATEMENTS OF CASH FLOWS			
Years ended March 31	2017	2016	2015
Cash flow (used in) provided by operating activities	(983)	1,987	5,271
Property, plant and equipment			
Cash used for additions	(934)	(1,417)	(2,435)
Cash used for acquisitions	(29,782)	-	(247)
Dividends paid	-	-	1,704

TABLE B – OPERATING RESULTS ($000's except for production &/unit amounts)

Years ended March 31	2017	2016	2015
Production – oil and liquids – bbls	126,228	153,423	176,630
Production – natural gas - mcf	698,545	715,734	786,758
Production – total - boe	242,652	272,712	307,756
Production – oil and liquids – bbls per day	346	419	484
Production – natural gas – mcf per day	1,914	1,956	2,156
Production – total – boe per day	665	745	843
Oil and natural gas liquids revenue	5,542	6,571	12,354
Natural gas revenue	1,570	1,738	2,904
Total production revenue	7,112	8,309	15,258
Processing fee revenue	680	712	852
Total production and processing fee revenue	7,792	9,021	16,110
Royalties expense	(818)	(760)	(3,317)
Production and transportation expense	(4,966)	(5,221)	(6,336)
Operating netback	2,008	3,040	6,457
Realized hedge gain (loss)	(274)	304	395
General and administrative expense	(1,273)	(896)	(893)
Transaction expense	(436)	(53)	-
Interest and other financing costs [1]	(433)	(376)	(444)
Cash flow (used in) from operations	(408)	2,019	5,515
Expenses not settled in cash – see Table D	(1,488)	(13,364)	(6,816)
Net loss and comprehensive loss	(1,896)	(11,345)	(1,301)
Net loss per share – basic and diluted	(0.48)	(3.66)	(0.42)
Royalties as % of total revenue	12%	9%	22%
Per unit analysis - $/bbl, mcf or boe			
Oil and liquids revenue – $/bbl	43.91	42.83	69.94
Natural gas revenue – $/mcf	2.25	2.43	3.69
Total petroleum revenue - $ /boe	29.31	30.47	49.58
Processing fee revenue - $ /boe	2.80	2.61	2.77
Royalties – $ /boe	(3.37)	(2.79)	(10.78)
Production and transportation – $ /boe	(20.47)	(19.14)	(20.59)
Operating net back – $ /boe	8.28	11.15	20.98
Realized hedge gain (loss) - $/boe	(1.13)	1.12	1.28
General and administrative –$/boe	(5.25)	(3.29)	(2.90)
Transaction - $/boe	(1.80)	(0.19)	-
Interest and other financing costs [1] –$/boe	(1.78)	(1.38)	(1.44)
Corporate netback – $/boe	(1.68)	7.40	17.92
Benchmark prices			
Natural gas – AECO 30-day spot - $/mcf	2.40	2.47	3.71
Oil - Edmonton light 40API -$/bbl	58.92	54.44	82.45
Oil - Hardisty Bow River 24.9 API - $/bbl	44.61	41.23	71.72
Medium oil differential - $/bbl	14.31	13.21	10.73

(1) Expenses settled with cash

TABLE C – OPERATING RESULTS FOR THE LAST EIGHT QUARTERS (Q)

$000's except for production and per unit amounts	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Production – oil and liquids – bbls	33,636	26,374	33,339	32,880	34,823	42,760	35,205	40,636
Production – natural gas – mcf	200,058	144,448	171,672	182,367	175,931	199,612	186,026	154,165
Production - total boe	66,979	50,449	61,950	63,274	64,145	76,029	66,209	66,330
Production–oils & liquids- bbls/d	374	287	362	361	383	465	383	447
Production –natural gas - mcf/d	2,223	1,570	1,866	2,004	1,933	2,170	2,022	1,694
Production – boe/d	744	548	673	695	705	826	720	729
Oil and natural gas liquids revenue	1,673	1,225	1,341	1,303	1,091	1,456	1,672	2,352
Natural gas revenue	539	421	371	239	247	547	532	412
Total production revenue	2,213	1,646	1,711	1,542	1,338	2,003	2,204	2,764
Processing fee revenue	187	176	158	159	158	160	237	156
Total production and fee revenue	2,400	1,822	1,868	1,701	1,496	2,163	2,441	2,920
Royalties	(271)	(252)	(270)	(25)	(160)	(318)	(267)	(15)
Production and transportation	(1,244)	(1,363)	(1,225)	(1,134)	(1,163)	(1,437)	(1,488)	(1,132)
Operating net back	885	207	374	542	173	408	686	1,773
Realized hedge gain (loss)	19	(164)	(77)	(52)	11	-	-	293
General and administrative	(479)	(254)	(312)	(227)	(229)	(228)	(255)	(238)
Transaction	(117)	(319)	-	-	-	-	-	-
Interest and other financing costs (1)	(150)	(78)	(112)	(93)	(93)	(81)	(109)	(93)
Cash flow from (used in) operations	158	(608)	(127)	170	(138)	99	322	1,735
(Expenses) income not settled in cash	808	(421)	(587)	(1,289)	4,511	(7,585)	(8,953)	(1,336)
Net income (loss)	966	(1,029)	(714)	(1,119)	4,373	(7,486)	(8,631)	399
Net income (loss) per share - basic	0.20	(0.24)	(0.19)	(0.36)	1.41	(2.42)	(2.79)	0.13
Net income (loss) per share – fully diluted	0.18	(0.24)	(0.19)	(0.36)	1.41	(2.42)	(2.79)	0.11
Royalties as % of revenue	12%	15%	16%	2%	12%	16%	12%	1%
Per unit analysis - $ per unit								
Oil and liquids revenue- $/bbl	49.74	46.44	40.21	39.66	31.33	34.06	47.48	57.87
Natural gas revenue – $/mcf	2.70	2.92	2.16	1.31	1.40	2.74	2.86	2.67
Production revenue – $/boe	33.03	32.63	27.62	24.38	20.87	26.35	33.28	41.67
Processing fee revenue - $/boe	2.80	3.50	2.54	2.51	2.46	2.10	3.58	2.35
Royalties –$/boe	(4.05)	(5.00)	(4.35)	(0.40)	(2.50)	(4.18)	(4.04)	(0.23)
Production & transportation–$/boe	(18.57)	(27.02)	(19.77)	(17.92)	(18.13)	(18.90)	(22.47)	(17.06)
Operating net back – $/boe	13.21	4.11	6.04	8.57	2.70	5.37	10.35	26.73
Realized hedge gain (loss) - $/boe	0.29	(3.25)	(1.25)	(0.82)	0.17	-	-	4.42
General and administrative - $/boe	(7.15)	(5.03)	(5.04)	(3.59)	(3.58)	(2.99)	(3.85)	(3.59)
Transaction - $/boe	(1.75)	(6.32)	-	-	-	-	-	-
Interest & financing costs (1)-$/boe	(2.24)	(1.55)	(1.81)	(1.47)	(1.45)	(1.08)	(1.64)	(1.40)
Corporate netback – $/boe	2.36	(12.04)	(2.06)	2.69	(2.15)	1.30	4.86	26.16
Benchmark prices								
Natural gas–AECO 30-day spot $/mcf	2.72	3.11	2.36	1.42	1.83	2.48	2.92	2.67
Oil - Edmonton light 40API - $/bbl	65.71	60.76	54.19	55.01	41.22	52.55	55.10	68.88
Oil-Hardisty Bow River 24.9API-$/ bbl	50.54	44.64	41.33	41.93	26.63	37.20	43.59	57.49
Medium oil differential - $/bbl	15.17	16.12	12.86	13.08	14.59	15.35	11.51	11.39

(1) Expenses settled with cash.

Table D – Income (expenses) not Settled in Cash

For the Last Three Years			
Years ended March 31	2017	2016	2015
Stock based compensation	(735)	-	-
Depletion and depreciation	(2,764)	(3,301)	(4,421)
Impairment	(738)	(7,000)	(2,610)
Accretion–asset retirement	(133)	(149)	(134)
Gain on disposal or acquisition of assets	2,070	-	306
Unrealized gain (loss) - hedges	83	(414)	1,436
Deferred tax	729	(2,500)	(1,393)
Total	(1,488)	(13,364)	(6,816)

For the Last Eight Quarters								
	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Stock based compensation	(203)	(155)	(81)	(296)	-	-	-	-
Depletion and depreciation	(947)	(513)	(645)	(658)	(607)	(845)	(917)	(933)
Impairment	(738)	-	-	-	5,200	(4,700)	(7,500)	-
Accretion–asset retirement	(40)	(26)	(33)	(34)	(36)	(40)	(36)	(36)
Gain on acquisition of assets	1,971	-	-	-	-	-	-	-
Gain on disposal of assets	-	99	-	-	-	-	-	-
Unrealized gain (loss) - hedges	36	175	172	(300)	(47)	-	-	(367)
Deferred tax	729	-	-	-	-	(2,000)	(500)	-
Total	808	(421)	(587)	(1,288)	4,510	(7,585)	(8,953)	(1,336)

EXPLANATION OF THE RESULTS OF OPERATIONS

Production revenue (refer to Tables B and C on pages 10 and 11)

Production

Average production for Q4 2017 (744 boe/d) is greater than Q4 2016 (705 boe/d) due to the production from the February 2017 acquisition which contributed 209 boe/d to the quarter's average of 744 boe/d. Despite the additional production from the first acquisition for the last two months of the year average production for 2017 (665 boe/d) was lower than for 2016 (745 boe/d) for two reasons:

- the Lindale oil property produced 108 boe/d in 2017 compared to 172 boe/d in 2016 due to natural declines, and
- the non-core properties sold effective October 1, 2017 reduced production in Q3 and Q4 2017 by approximately 90 boe/d.

Realized prices

Carmangay, Lindale, and Warburg produce light oil while Bantry produces medium gravity oil which realizes a lower price than light oil. The differential can vary considerably from quarter to quarter as shown in Table C on page 11.

Benchmark prices

Benchmark prices are provided in Tables B and C. 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 2017 differential between light and medium gravity oil was $14.31/bbl compared to the 2016 differential of $13.21/bbl as shown in Table B. Benchmark natural gas prices averaged moderately lower in 2017 ($2.40/mcf) compared to 2016 ($2.47/mcf).

Gains and losses on commodity contracts

The realized gain on hedges in fiscal 2016 amounted to $304 of which $293 related to financial commodity price contracts which expired June 30, 2015. The table below includes the financial commodity price contracts outstanding during 2017 generating a realized loss on hedges of $274:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
February 1, 2016	December 31, 2016	bbls/day	50	NYMEX WTI CDN	$50.00
April 1, 2016	December 31, 2016	bbls/day	50	NYMEX WTI CDN	$55.00
May 1, 2016	December 31, 2016	bbls/day	50	NYMEX WTI CDN	$60.00
May 1, 2016	October 31, 2016	GJ/day	500	CGPR AECO CDN	$1.50
March 1, 2017	February 28, 2018	GJ/day	700	CGPR AECO CDN	$2.70
February 1, 2017	January 31, 2018	bbls/day	50	NYMEX WTI CDN	$70.00
March 1, 2017	February 28, 2018	bbls/day	50	NYMEX WTI CDN	$70.52

Commodity price risk management was addressed in the Liquidity section on page 8, which includes the details of all commodity price contracts outstanding as at July 26, 2017.

Royalties (refer to Tables B and C on pages 10 and 11)

The expense for royalties is a mix of crown, freehold (including related mineral taxes) and gross overriding royalties. 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 following table analyzes the significant components of royalty expense which varies with production volumes which are also presented in the table:

Royalties expense Periods ended March 31	3 months Q4 2017	3 months Q4 2016	12 months 2017	12 months 2016
Crown royalties - oil	22	22	94	158
Crown royalties – natural gas and liquids	139	69	374	359
Crown royalties - gas cost allowance	(67)	(72)	(422)	(658)
Freehold royalties – all commodities	117	115	580	653
Gross overriding royalties – all commodities[1]	60	26	192	248
Total	271	160	818	760
Royalties as a % of petroleum revenue	12%	12%	12%	9%
Oil production – bbls[2]	21,906	26,070	87,522	118,563
Liquids production – bbls[2]	11,551	8,753	38,279	34,860
Natural gas production – mcf[2]	197,453	175,931	696,549	715,734
Realized oil price - $/bbl[2]	54.88	31.33	49.00	46.37
Realized liquids price – $/bbl[2]	37.33	25.05	35.38	30.44
Realized natural gas price - $/mcf[2]	2.64	1.72	2.21	2.43

[1]Includes royalty to related party – see page 18.

[2]Excludes production from royalty interests.

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 2017 the Company realized gas cost allowance recoveries of $422 of which $141 related to prior periods.

Production & transportation costs and processing fee revenue
Refer to Tables B and C on pages 10 and 11

Property, plant and equipment includes 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 following table along with the significant components of production and transportation costs:

Production and transportation expense Periods ended March 31	3 months Q4 2017	3 months Q4 2016	12 months 2017	12 months 2016
Transportation, gathering and processing	240	220	818	1,031
Workover, repairs and maintenance	237	206	1,103	1,128
Property taxes, lease rentals and regulatory fees	86	142	720	675
Other production costs	680	595	2,325	2,387
Total production and transportation costs	1,244	1,163	4,966	5,221
Processing fee revenue	(187)	(158)	(680)	(712)
Production & transportation expense less processing fees	1,057	1,005	4,286	4,509
Workover, repairs and maintenance – $/boe	3.55	3.21	4.54	4.14
All other costs above – $/boe	15.02	14.92	15.93	15.00
Total production & transportation costs –$ /boe	18.57	18.13	20.47	19.14
Processing fee revenue – $/boe	(2.80)	(2.46)	(2.80)	(2.61)
Production activity –$ /boe	15.77	15.67	17.67	16.53

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).

2017 production and transportation costs/boe ($20.47/boe) are higher than 2016 ($19.14/boe) primarily due to the higher costs of workovers, repairs, maintenance on a per boe basis being $4.55/boe in 2017 compared to $4.14/boe in 2016.

General and administrative expense and transaction expense
Refer to Tables B and C on pages 10 and 11

General and administrative expense Periods ended March 31	3 months Q4 2017	3 months Q4 2016	12 months 2017	12 months 2016
Personnel	336	130	860	539
Professional fees	92	35	204	163
Office and other	51	64	209	196
Total general and administrative	479	229	1,273	898
General and administrative – $/boe	7.15	3.58	5.25	3.29

Transaction expense	117	-	436	52
Transaction – $/boe	1.75	-	1.98	0.19

2017 office and other costs include the costs of an upgrade of the Company's computer and information technology systems. 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 2017 compared to 2016 relating to the equity financing, sale of non-core assets and acquisitions.

Transaction costs fluctuate significantly between periods and were significant in 2017 due to the costs related to the dispositions and acquisitions (e.g. professional fees for legal, geological, reserve evaluation) as the Company executed on the new corporate strategy.

Interest and other financing costs
Refer to Tables B and C on pages 10 and 11

Periods ended March 31	3 months Q4 2017	3 months Q4 2016	12 months 2017	12 months 2016
Accretion of asset retirement obligations	40	36	133	148
Interest on credit facility	66	74	256	307
Credit facility fees and costs	84	19	177	69
Finance expense for the year	190	129	566	524

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. Q4 2017 includes the commitment and standby fees for the higher credit facility limit which increased to $26.0 million concurrent with the property acquisitions as described in the Highlights section of this MD&A.

Stock based compensation
Refer to Table D on page 12

The Company granted options for voting common shares to directors, officers and consultants as 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 sets the terms (including exercise price, date of expiry and vesting periods) for the options at the time of grant.

In June, August and November of 2017, the Company granted options for 397,000 voting common shares with an exercise price of $4.50 per share under option and which expire 7 years after the date of grant. Those granted in June and August of 2016 (options for 315,000 voting common shares) vest 1/3 immediately and 1/3 on each of the next two anniversaries. Those granted in November 2017 (options for 82,000 voting common shares) vest 1/3 on each of the first, second and third anniversaries. The fair value of the options at the date of measurement was determined based on a Black-Scholes calculation resulting in total estimated expense of $1,209 to be amortized over the vesting periods. Stock based compensation expense for the year ended March 31, 2017 amounted to $735 which is a significant portion of the total of $1,209 due to the accelerated vesting of the first round of options. The following were used in the Black-Scholes calculation:

Exercise price	$4.50
Volatility	73%
Expected option life	7.0 years
Dividend	$nil
Risk-free interest rate	0.5%

The Company is not listed on a stock exchange. The exercise price of $4.50 is the same price at which the Company issued voting common shares in Q2 2017. The estimate of volatility is based on a sample of peer junior oil and natural gas producers listed on a Canadian stock exchange.

In May 2017, the Company granted options for 325,000 voting common shares to directors, officers, employees and consultants. These options have an exercise price of $5.00 per share under option, expire 7 years after the date of grant and vest one third on each of the first, second and third anniversaries. The exercise price of $5.00 is the same price at which the Company issued voting common shares in Q4 2017.

Depletion, depreciation and impairment
Refer to Table D on page 12

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 exist at March 31, 2017 and 2016 resulting in impairment for the year ended March 31, 2017 of $738 (2016 - $7,000). For both years impairment tests were performed on all cash generating units and impairment or impairment recovery was recorded on each of them as described in Note 4 to the Audited Financial Statements as at and for the years ended March 31, 2017 and 2016. 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 lower production in 2017 and a lower depletable base, a result of impairment recorded in prior years and low development expenditures in recent years, reduced the depletion expense to $2,764 in 2017 compared to $3,301 in 2016.

Deferred taxes

Refer to Tables D on page12

Due to the uncertainly of the Company generating sufficient future taxable income against which deductible temporary differences could be applied, deferred tax assets have not been recognized. The deferred tax recovery in 2017 of $729 relates to the gain ($2,700 which net of the related deferred income taxes amounts to $1,971) on acquisition of oil and natural gas assets acquired in Q4 2017, for which the fair value of the property, plant and equipment acquired exceeded the cash consideration paid. The deferred tax expense of $2.5 million in 2016 relates to impairment of the deferred tax assets recorded in prior years.

The Company's tax pools are set out below:

Nature of tax pool	%(1)	March 31, 2017	March 31, 2016
Canadian oil and gas property expense COGPE)	10	35,491	17,552
Foreign resource expenses	10	6,601	7,334
Canadian development expense (CDE)	30	3,948	3,310
Undepreciated capital cost (UCC)	25	12,974	6,789
Share issue costs	20	252	15
Non-capital losses carried forward	100	28,147	22,988
Total tax pools		87,413	57,988

(1) maximum rate of deduction

The above non-capital losses carried forward expire between 2026 and 2037.

RELATED PARTY TRANSACTIONS

Related party transactions are disclosed in Note 10 of the Audited Financial Statements as at March 31, 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. Gross over-riding royalties (GORR) payable to the President and Chief Executive Officer, amounted to $55 in 2017 (2016 - $122). The reduction is due to the lower volumes of both oil and natural gas in 2017 and the lower average natural gas prices.

During 2017 $31 (2016 - $38) was recovered for office rent from Front Range Resources Ltd. (formerly Stonehaven Exploration Ltd.), a company with directors in common.

NEW ACCOUNTING POLICIES

No new or amended accounting standards or interpretations were adopted during 2017.

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 Audited 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 Audited 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 Audited Financial Statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's Audited Financial Statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of 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 years ended March 31, 2017 and 2016. Certain estimates and judgments are described in Note 2 to the Audited Financial Statements for the years ended March 31, 2017 and 2016. 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 gas reserves at the current and prior year end were evaluated and reported on by an 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 various 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 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 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.

Asset retirement obligations

Asset retirement obligations are estimated for all wells and facilities in which the Company has an interest whether or not reserves have been attributed to those assets by the 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 LLR and the Company's own experience, including historical costs incurred for abandonment or reclamation. To estimate future retirement costs, the Company applied a 1.5% 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 asset retirement obligations which are a component of a business combination, the Company uses a market discount rate which is usually a 10% discount rate.

Share based payments

The Company's accounting policy for "share-based payments" was applied to account for the options granted during the year ended March 31, 2017, which was the first year in which the Company granted options to acquire voting common shares. The costs of share-based payments 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 recently issued voting common shares. 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 a sample of peer junior oil and natural gas producers listed on a Canadian stock exchange.

Deferred tax

At each period end 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 derivatives

The estimated fair values of derivative financial instruments resulting in financial assets and liabilities, by their very nature, require estimates. The Company hedges some petroleum sales through the use of financial derivatives and estimates the mark to market value at each reporting period by applying estimated forward prices for the contracted hedge volumes.

Cash-generating units

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 an 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 asset retirement 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.

OFF BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements. The hedging contracts on future oil and natural gas prices have been disclosed above and in the Audited Financial Statements 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 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.

The Company's revenues, profitability and 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 large and rapid fluctuations 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 11 of the Audited Financial Statements for the year ended March 31, 2017 for additional analysis of these risks.

The Company’s activities expose it to a variety of financial risks that arise as a result of 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 cash flow from operating activities 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 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 in material compliance 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 of these risks, nor are all such risks insurable, however management is of the opinion 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 to the extent possible.

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 Audited 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 Audited Financial Statements by adjusting for the change in non-cash working capital and asset retirement expenditures (if any) as follows:

Years ended March 31,	2017	2016
Cash flow (used in) from operations per Table B (page 10)	(408)	2,019
Change in non-cash working capital for operating activities (1)	(575)	(31)
Cash (used in) provided by operating activities (1)	(983)	1,987

(1) Per Statements of Cash Flows – Audited 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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