Q3
2018

Management's Discussion and Analysis

Chinook Energy Inc. | 1000, 517 – 10th Avenue S.W. Calgary, Alberta T2R 0A8 TSX:CKE

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. and its wholly owned subsidiaries (collectively, "our", "we" or "us") for the three and nine months ended September 30, 2018 and 2017 and should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes as at and for the three and nine months ended September 30, 2018 and 2017 (the "Interim Financial Statements") and the audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2017 and 2016 (the "Audited Financial Statements). This MD&A is based on information available as at November 8, 2018.

The term "third quarter" or "year to date" or similar terms are used throughout this document and refer to the three or nine months ended September 30, 2018, respectively. The term "current reporting periods" or similar terms are used throughout this document and refer to both the three and nine months ended September 30, 2018, in this respective order. The term "same period(s) of 2017" or "comparative period(s)" or similar terms are used throughout this document and refer to the three or (and) nine months ended September 30, 2017, depending on the 2018 period(s) under discussion. The term "reported periods" or similar terms are used throughout this document and refer to both the three and nine months ended September 30, 2018 and 2017. The term "fourth quarter", "first quarter" or "second quarter" or similar terms are used throughout this document and refer to the three months ended December 31, 2017, March 31, 2018 or June 30, 2018, respectively.

This MD&A contains measures which are not prescribed by International Financial Reporting Standards ("IFRS") ("non-GAAP") and, therefore, may not be comparable with the calculations of similar measures presented by other companies. Statements throughout this MD&A that are not historical facts may be considered "forward-looking statements". Readers should read the advisories under the headings "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2017 ("AIF"), can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The Interim Financial Statements have been prepared in accordance with International Accounting Standard 34 'Interim Financial Reporting' using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board. They include the accounts of our direct subsidiaries, all of which are wholly owned.

All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per unit amounts or as otherwise noted.

Certain balances in the comparative periods have been reclassified to conform to the current reporting periods' presentation.

Introduction to Chinook

We are a Calgary-based upstream oil and natural gas company whose main business activities include exploration, development and production of natural gas liquids and natural gas. We are focused on realizing per share growth from our large contiguous Montney liquids-rich natural gas position at our Birley/Umbach property in northeast British Columbia ("BC").

We are incorporated under the laws of the Province of Alberta, Canada. Our common shares are listed and posted for trading on the Toronto Stock Exchange under the symbol “CKE”. Our head office and principal address is Suite 1000, 517 – 10th Avenue S.W., Calgary, Alberta, Canada T2R 0A8.

Operating and Financial Highlights

	Three months ended September 30				Nine months ended September 30			
		2018		2017		**2018**		2017
OPERATIONS								
Production (1)								
Natural gas liquids (boe/d)		**707**		405		**620**		442
Natural gas (mcf/d)		**24,454**		14,109		**20,210**		17,051
Crude oil (bbl/d)		**24**		19		**22**		22
Average daily production (boe/d) (2)		**4,807**		2,776		**4,010**		3,306
Sales Prices								
Average natural gas liquids price ($/boe)	**$**	**63.73**	$	42.07	**$**	**63.46**	$	46.22
Average natural gas price ($/mcf)	**$**	**1.54**	$	1.20	**$**	**1.74**	$	2.31
Average oil price ($/bbl)	**$**	**71.35**	$	51.49	**$**	**71.82**	$	57.52
Netback (3)								
Average commodity pricing ($/boe)	**$**	**17.59**	$	12.61	**$**	**18.97**	$	18.49
Royalty recovery (expense) ($/boe)	**$**	**-**	$	0.52	**$**	**(0.07)**	$	0.09
Realized (loss) gain on commodity price contracts ($/boe)	**$**	**(0.17)**	$	6.54	**$**	**(0.28)**	$	2.70
Net production expense ($/boe) (3)	**$**	**(9.74)**	$	(12.32)	**$**	**(11.06)**	$	(11.77)
Operating netback ($/boe) (2) (3)	**$**	**7.68**	$	7.35	**$**	**7.56**	$	9.51
Wells Drilled								
Exploratory wells (net)		**-**		-		**2.00**		-
Natural gas wells (net)		**-**		-		**-**		3.63
FINANCIAL ($ thousands, except per share amounts)								
Petroleum & natural gas revenues, net of royalties	**$**	**7,778**	$	3,351	**$**	**20,691**	$	16,772
Adjusted funds flow (3)	**$**	**2,285**	$	647	**$**	**4,592**	$	3,878
Per share - basic & diluted ($/share)	**$**	**0.01**	$	-	**$**	**0.02**	$	0.02
Cash inflow (outflow) from operating activities	**$**	**1,132**	$	(1,352)	**$**	**633**	$	3,483
Net (loss) income	**$**	**(1,944)**	$	(3,923)	**$**	**(6,513)**	$	4,246
Per share - basic and diluted ($/share)	**$**	**(0.01)**	$	(0.02)	**$**	**(0.03)**	$	0.02
Capital expenditures	**$**	**-**	$	14,733	**$**	**2,677**	$	31,791
Net (debt) surplus (3)	**$**	**(713)**	$	3,616	**$**	**(713)**	$	3,616
Total assets	**$**	**120,572**	$	155,799	**$**	**120,572**	$	155,799
Common Shares (thousands)								
Weighted average during period								
- basic		**223,605**		217,115		**223,591**		216,721
- diluted		**223,605**		217,115		**223,591**		217,144
Outstanding at period end		**223,605**		217,115		**223,605**		217,115

(1) Throughout this MD&A our production is presented in either barrels of oil ("bbl"), thousands of cubic feet ("mcf") or barrels of oil equivalent ("boe"); production per day is presented as bbl/d, mcf/d, and boe/d, respectively; commodity prices or revenues and expense per sales are presented as $/bbl, $/mcf, and $/boe, respectively. Production volumes and sales volumes are equal and are used interchangeably throughout this MD&A.

(2) May not be additive due to rounding.

(3) Non-GAAP measures which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Operations

Petroleum and Natural Gas Production Volumes

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Natural gas liquids (boe/d)	**707**	405	**620**	442
Natural gas (mcf/d)	**24,454**	14,109	**20,210**	17,051
Crude oil (bbl/d)	**24**	19	**22**	22
Total (boe/d)	**4,807**	2,776	**4,010**	3,306

During the third quarter our production increased by 2,031 boe/d compared to the same quarter of 2017. This increase was due to our 2016 and 2017 Montney drilling programs at our Birley/Umbach area that resulted in seven (6.27 net) horizontal wells. Six (5.33 net) of these seven wells contributed an additional 1,700 boe/d during the third quarter compared to the same quarter of 2017. Also, our third quarter production was unaffected by third party constraints whereas the comparative quarter's production was effected by an earlier and longer than scheduled Enbridge McMahon Plant (the "McMahon Plant") turnaround.

Integrity and maintenance issues on Enbridge's Oak 16" gathering line (the "Oak Pipeline") and a longer than scheduled McMahon Plant turnaround, respectively, restricted our volumes during the year to date and same period of 2017. Despite these restrictions, year to date production volumes increased 704 boe/d as we benefited from additional production from our new Birley wells. Specifically, the year to date restrictions, which began in November 2017, continued until a temporary pipeline was put in place in early April. A permanent replacement for this temporary pipeline is expected during the first half of 2019. There were further temporary restrictions imposed on us through early April and most of June. These issues were all resolved in early July.

The third quarter's production volumes increased 9% compared to the 4,413 boe/d reported during the second quarter. This increase was caused by the reduced effect of the previously discussed Oak Pipeline integrity and maintenance issues. As previously discussed, the resulting restrictions affected portions of the second quarter but were resolved in early July.

Our production volumes were partially suspended immediately following the October 9, 2018 rupture of one of Enbridge's natural gas T-South Pipelines ("T-South Pipelines"). Enbridge has two natural gas T-South Pipelines with the smaller diameter pipeline put back into service on October 12, 2018. The larger diameter ruptured pipeline was repaired and made operational in November 2018. Since being put back into service, both of the T-South Pipelines are operating at reduced pressures. These reduced operating pressures are expected to continue through the winter season. Because purchasers were unable to take away volumes from the BC natural gas market point, it had an unfavorable effect on October's BC Station 2 benchmark price. As a result, since the rupture of the third party's pipeline through the remainder of October, we voluntarily suspended production except to fulfill our approximate 5,425 GJ/d Chicago City Gate priced commitment. In response, effective November 1, 2018, our natural gas production volumes sold at the Chicago City Gate benchmark increased to approximately 10,500 GJ/d as we obtained additional pipeline capacity. We continue to evaluate increasing our natural gas production once we observe the semblance of market fundamentals to the BC Station 2 benchmark price.

Petroleum and Natural Gas Revenues and Realized Pricing

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	**2018**	2017	**2018**	2017
Natural gas liquids sales	**$ 4,148**	$ 1,566	**$ 10,733**	$ 5,580
$/boe	**63.73**	42.07	**63.46**	46.22
Natural gas sales	**$ 3,476**	$ 1,561	**$ 9,599**	$ 10,757
$/mcf	**1.54**	1.20	**1.74**	2.31
Oil sales	**$ 155**	$ 92	**$ 432**	$ 351
$/bbl	**71.35**	51.49	**71.82**	57.52
Petroleum & natural gas revenue	**$ 7,779**	$ 3,219	**$ 20,764**	$ 16,688
$/boe	**17.59**	12.61	**18.97**	18.49

Our petroleum and natural gas revenues for the current reporting periods increased compared to the same periods of 2017. This resulted from both higher production volumes and overall realized pricing. As previously discussed, the higher production volumes resulted from previous years' Montney drilling programs at our Birley/Umbach area. The higher overall realized pricing was due to changes in various commodity benchmarks. The current reporting periods' higher overall realized pricing was aided by a higher ratio of natural gas and its associated liquid production contributed from our Birley/Umbach area relative to our total production volumes. This area's production is condensate rich and its natural gas production has a higher heat content compared to the production from our other operations resulting in higher realized pricing.

Our overall realized price during the third quarter was relatively unchanged from the $17.75/boe reported during the second quarter as higher benchmark pricing for natural gas was offset by lower petroleum benchmarks.

Benchmark Prices

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Natural gas liquids				
Canadian light sweet (1) ($/bbl)	**$ 81.88**	$ 57.15	**$ 78.18**	$ 60.57
Natural gas				
BC Westcoast Station 2 (2) ($/mcf)	**$ 1.30**	$ 0.99	**$ 1.44**	$ 1.97
Chicago City Gate (3) (US$/mcf)	**$ 2.76**	$ 2.91	**$ 2.87**	$ 3.04

(1) Central market point for Canadian crude oil.
(2) Market point for BC natural gas.
(3) Market point for mid-Eastern United States natural gas.

NGL Pricing

During the current reporting periods, consistent with higher Canadian light sweet oil and various other liquids and condensate benchmarks, our realized NGL pricing of $63.73/boe and $63.46/boe increased compared to the same periods of 2017. Our NGL price is a blend of prices received for a range of liquids from ethane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however, we benchmark our liquids in reference to Canadian light sweet oil. The ratio of our NGL price relative to Canadian light sweet oil increased to 78% and 81% for the current reporting periods from 74% and 76% for the same periods of 2017. The current reporting periods' ratios include the favorable effects of both an increase in the weighted average production volumes contributed from our liquid-rich Birley/Umbach area relative to our total production volumes and condensate pricing increasing at equivalent rates relative to the Canadian light sweet benchmarks.

Our realized NGL price decreased 4% during the third quarter compared to the $66.65/boe realized price reported during the second quarter despite no change in the condensate benchmark. There was a higher ratio of production from our Birley/Umbach area relative to our total production volumes during the second quarter as we managed our operations to maximize liquid recoveries given volume restrictions caused by the Oak Pipeline integrity and maintenance issues.

Natural Gas Pricing

Our realized natural gas price of $1.54/mcf during the third quarter increased compared to the $1.20/mcf for the same quarter of 2017. Inversely, our natural gas price of $1.74/mcf during the year to date decreased compared to $2.31/mcf for the same period of 2017. These realized natural gas pricing changes are due to both changes in benchmark pricing and in the weighted average ratio of natural gas production sold at each benchmark price relative to total natural gas production. Generally, because we sell the majority of our natural gas production at the BC Station 2 benchmark, the change in our current reporting periods' realized natural gas prices, compared to the same periods of 2017, correspond to the changes in this benchmark. However, we also sell a portion of our natural gas production at the Chicago City Gate benchmark where we have a firm commitment of approximately 5,425 GJ/d through to October 31, 2020. In addition, effective November 1, 2018, we obtained additional capacity through to March 31, 2019 of approximately 4,250 GJ/d, albeit with a larger associated transportation toll, also sold at the Chicago City Gate benchmark. This benchmark modestly decreased during the current reporting periods compared to the same periods of 2017. However, despite these modest decreases, selling our natural gas at Chicago City Gate benchmark pricing results in us realizing a significant premium compared to BC Station 2 pricing. Specifically, during the current reporting periods we sold 21% and 26% of our natural gas production at this benchmark compared to 28% and 24% during the same periods of 2017. The decrease in the third quarter ratio resulted from higher production volumes relative to our firm commitment priced at the Chicago City Gate benchmark whereas the increase in the year to date ratio was the absence of last year's June restrictions which prevented us from delivering volumes at Chicago pricing. As previously mentioned, contributing to higher realized natural gas pricing were higher ratios of natural gas production from our Birley/Umbach area relative to our total natural gas production. Our Birley/Umbach natural gas production has a higher heat content compared to the natural gas production from our other operations resulting in higher realized natural gas pricing.

Our realized natural gas price increased 10% during the third quarter compared to the $1.40/mcf realized price reported during the second quarter. This increase was due to higher benchmark pricing for both BC Station 2 and Chicago City Gate.

Royalties

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Royalty expense (recovery)	**$ 1**	$ (132)	**$ 73**	$ (84)
Per sales ($/boe)	**$ -**	$ (0.52)	**$ 0.07**	$ (0.09)
Percent of revenues (%)	**-**	(4)	**-**	(1)

We are reporting negligible royalties for the reported periods. During 2017, we were granted royalty credits as part of BC's Infrastructure Royalty Credit Program (the "Infrastructure Program"). This program provides credits on our Birley/Umbach development only after sufficient crown royalties have been generated by specific wells. We recognized $0.3 million and $0.8 million of these credits through a decrease to our royalties during the current reporting periods. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program. The 12 (10.47 net) Birley/Umbach wells that have qualified for this credit program bear a minimum crown royalty rate of 6% prior to applying the credits from the Infrastructure Program. Through the remainder of 2018 and into 2019 we are forecasting nominal BC crown royalties as a result of these credit programs combined with being a BC Montney focused play. Specifically, the comparative periods' recoveries were caused by adjustments to our previous Alberta Gas Cost Allowance estimates. Royalties in Alberta are no longer significant to our operations. Overriding and freehold royalties will continue to be payable.

Financial Commodity Price Contracts

To help mitigate commodity price risk, we enter into financial commodity price contracts which assist us in better managing our future adjusted funds flow. This provides more certainty within determined commodity price ranges as to what we will receive on a portion of our liquids and/or natural gas sales volumes. While these financial contracts may have opportunity costs when commodity benchmarks exceed the contracted prices, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Also, in accordance with the terms of our demand credit facility (see "Credit Facility"), if we have either net debt or debt draws, we are required to enter into commodity price contracts covering a minimum amount of our forecasted twelve month combined production volumes. We continuously review the need or requirement to utilize financial contracts.

When we have commodity price contracts outstanding at the end of a reporting period, they are reported at their approximated fair value on the date of the financial statements. This estimated fair value is partially determined through the difference in the referenced market forward price of the respective commodity over the remaining periods of the contracts compared to our received price multiplied by the remaining notional volumes. Volatility in forward commodity pricing and decreases in the remaining notional volumes will result in changes in the fair value of our derivative contracts from one period to the next. The change in the fair values between reported periods are recognized in net income (loss) as unrealized gains or losses on commodity price contracts. Realized gains or losses from these financial commodity price contracts are recognized in net income (loss) over the settlement term.

For the reported periods, we had the following realized and unrealized gains and losses from our commodity price contracts:

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Realized loss (gain) on commodity price contracts	**$ 76**	$ (1,669)	**$ 302**	$ (2,438)
Unrealized loss (gain) on commodity price contracts	**352**	280	**938**	(1,307)
Loss (gain) on commodity price contracts	**$ 428**	$ (1,389)	**$ 1,240**	$ (3,745)
Realized (loss) gain on commodity price contracts ($/boe)	**$ (0.17)**	$ 6.54	**$ (0.28)**	$ 2.70

During the current reporting periods, we realized losses on our Chicago City Gate price indexed contract where our contracted price of US$2.68/mmbtu was lower than this benchmark price. If we had included these losses in our natural gas revenues, we would have reported an adjusted natural gas sales price for the current reporting periods of $1.51/mcf and $1.69/mcf compared to our reported price of $1.54/mcf and $1.74/mcf.

Outstanding Commodity Price Contracts

As at September 30, 2018, our outstanding commodity price contracts had the following terms:

Remaining Contractual Term	Notional Volumes	Index and Company's Received Price
Natural gas swap		
October 1, 2018 to March 31, 2019	6,000 mmbtu/d	Chicago City Gate Monthly US$2.68/mmbtu
Natural gas collars		
April 1, 2019 to June 30, 2019	6,000 mmbtu/d	NYMEX (1) US$1.935/mmbtu to US$3.16/mmbtu
July 1, 2019 to September 30, 2019	6,000 mmbtu/d	NYMEX (1) US$2.00/mmbtu to US$3.21/mmbtu
Natural gas differential swaps		
April 1, 2019 to June 30, 2019	6,000 mmbtu/d	Price at Chicago = NYMEX (1) less US$0.435/mmbtu
July 1, 2019 to September 30, 2019	6,000 mmbtu/d	Price at Chicago = NYMEX (1) less US$0.41/mmbtu
Crude oil swaps		
April 1, 2019 to June 30, 2019	120 bbl/d	WTI (2) CAD$84.20/bbl
July 1, 2019 to September 30, 2019	120 bbl/d	WTI (2) CAD$84.00/bbl

(1) NYMEX is the abbreviation for the New York Mercantile Exchange.
(2) WTI is the abbreviation for West Texas Intermediate.

The combination of the NYMEX natural gas collars and differential swaps provide us a minimum and maximum price on notional volumes sold at Chicago City Gate Monthly pricing during the second and third quarters of 2019. Over these remaining contractual terms, for purposes of our minimum commodity price contract requirement per our amended demand credit facility agreement (see “Credit Facility”), our lender has given us credit for notional volumes of 6,000 mmbtu/d for the combination of the natural gas collars and differential swaps. The crude oil swaps secure the price we receive for our condensates.

Mark-to-Market

All of our commodity price contracts were in a loss position because forward Chicago City Gate, NYMEX and WTI benchmark pricing had increased relative to our contracted pricing. This resulted in unrealized losses of $0.4 million and $0.9 million for the current reporting periods. The year to date unrealized loss resulted in an equivalent mark-to-market current financial liability as at September 30, 2018.

Net Production Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Production & operating	**$ 4,551**	$ 3,373	**$ 12,886**	$ 11,319
Less:				
Processing & gathering revenues	**(245)**	(226)	**(774)**	(694)
Net production expense [(1)]	**$ 4,306**	$ 3,147	**$ 12,112**	$ 10,625
Net production expense ($/boe) [(1)]	**$ 9.74**	$ 12.32	**$ 11.06**	$ 11.77
Production expense ($/boe)	**$ 10.29**	$ 13.21	**$ 11.77**	$ 12.54

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

On a boe basis, production & operating expenses for the current reporting periods decreased compared to the same periods of 2017. These decreases were largely due to higher reported volumes with our third quarter volumes being relatively unaffected by third party restrictions. Specifically, during the third quarter our Birley/Umbach area averaged a production expense of $7.68/boe as compared to the overall reported production expense of $10.29/boe.

For the year to date, production & operating costs were affected by the previously mentioned Oak Pipeline integrity issue and the resulting production restriction. In addition, to prevent our production from freezing, we also incurred higher labour and steamer costs to flow restricted volumes through the extremely cold winter weather. These higher costs could have been avoided had our production been unimpeded. For the same period of 2017, our operating costs were effected by a longer than expected McMahon Plant turnaround. Both of these restrictions had the effect of increasing the contribution, on a boe basis, from fixed operating costs relative to total operating costs.

Although there are no significant maintenance or turnaround programs scheduled for the remainder of 2018, the rupture on one of the T-South Pipelines will affect our fourth quarter of 2018 production volumes through to its back in service date and thereafter as it continues to operate at a reduced pressure. Because of these expected lower production volumes, compared to the third quarter, although we anticipate a decrease in our overall production expense, we expect on a boe basis that it will be higher for the remainder of 2018.

We started reporting new toll revenue in June 2017 from our 12" Aitken Creek Pipeline which is directly connected to the Alliance Pipeline. This resulted in higher processing and gathering revenues during the year to date compared to the same period of 2017 but as partially offset by lower compression and gathering income at our Martin Creek property caused by lower third party throughput. Our Aitken Creek Pipeline passes through our Birley, Martin Creek and Black Conroy lands and provides us with optionality upon the future development of a gas plant to flow directly to the Alliance Pipeline with access to the Chicago market, BC Station 2 via Enbridge's T-North Pipeline or connect to TCPL's North Montney expansion when completed in 2019 or 2020.

Operating Netback

The following table outlines the calculation of our operating netback[(1)]:

	Three months ended September 30		Nine months ended September 30	
Per sales ($/boe)	**2018**	2017	**2018**	2017
Average commodity pricing	**$ 17.59**	$ 12.61	**$ 18.97**	$ 18.49
Royalty recovery (expense)	**-**	0.52	**(0.07)**	0.09
Realized (loss) gain on commodity price contracts	**(0.17)**	6.54	**(0.28)**	2.70
Net production expense [(1)]	**(9.74)**	(12.32)	**(11.06)**	(11.77)
Operating netback [(1)]	**$ 7.68**	$ 7.35	**$ 7.56**	$ 9.51

(1) Non-GAAP measures which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A. Operating netback may not be additive to due rounding.

Our operating netback increased during the third quarter but decreased during the year to date compared to the same periods of 2017. The third quarter increase was due to significantly higher average commodity pricing and lower net production expense but partially offset by the absence of a $6.54/boe gain from realized commodity price contracts as included in the comparative quarter. Similarly, the year to date change also includes higher average commodity pricing and lower net production expense but these favorable effects were more than offset by the absence of a $2.70/boe gain from realized commodity price contracts as included in the comparative period.

Take or Pay Contract and Other (Income) Losses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Take or pay contract revenue	**$ (1,032)**	$ (1,025)	**$ (3,020)**	$ (1,925)
Take or pay contract expense	**$ 1,144**	$ 1,226	**$ 3,444**	$ 2,302
Other (income) losses	**$ (4)**	$ (51)	**$ (27)**	$ 249

During the reported periods, we incurred a net fee for a take or pay processing agreement which we partially mitigated by purchasing production from a third party. This net fee decreased during the current reporting periods compared to the same periods of 2017 because we mitigated our exposure to it through an increase in the purchase of production from a third party. We have partially mitigated our continued exposure to this fee at least through to the first quarter of 2019. The take or pay processing agreement has successive lower annual firm commitments through to its expiry on March 31, 2021.

General & Administrative ("G&A") Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
G&A expense before recoveries	**$ 1,262**	$ 1,885	**$ 4,487**	$ 6,640
Recoveries	**(325)**	(712)	**(1,392)**	(2,320)
G&A expense	**$ 937**	$ 1,173	**$ 3,095**	$ 4,320
Per sales ($/boe)	**$ 2.12**	$ 4.59	**$ 2.83**	$ 4.79

For the current reporting periods, we realized lower G&A expenses implemented throughout 2017 including lower staffing costs due to reductions in headcount, a lower number of directors, reduced employee benefits and reduced information system costs. For the year to date, we further reduced our headcount by 40% and suspended an employee benefit program. We estimate this will result in additional G&A cost savings of approximately $1.4 million per year. Furthermore, a reduced work week was implemented from May to September 2018. In addition, as a result of reporting an onerous contract non-cash charge during 2017, an additional $0.4 million of rent expenditures during the year to date that was previously reported as G&A expense instead reduced our onerous contract provision (see "Onerous Contract and Indemnifications"). If current rental market conditions remain the same or similar, we anticipate significantly lower rent costs commencing in mid-2019 upon our lease expiration.

Partially offsetting the above G&A decreases were lower G&A recoveries. With lower compensation costs combined with reduced capital expenditures, our capitalized G&A, capital and other associated G&A recoveries decreased by $0.4 million and $0.9 million during the current reporting periods compared to the same periods of 2017.

G&A on a boe basis also decreased during the current reporting periods compared to the same periods of 2017 as a result of the decrease in overall G&A expense described above combined with higher production.

Severance Costs

($ thousands)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Severance costs	**$ 113**	$ 163	**$ 834**	$ 671

Severance costs incurred during the current reporting periods related to staffing reductions resulting from a continuing assessment of our staffing requirements. As previously discussed, during the year to date we reduced our headcount by 40%.

Exploration and Evaluation Expense

($ thousands)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Exploration & evaluation expense	**$ -**	$ 66	**$ 111**	$ 261

Exploration and evaluation expense during the year to date was in respect of exploratory lease rental costs.

Depletion, Depreciation and Amortization ("DD&A") Expense

($ thousands, except where noted)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Depletion, depreciation & amortization	**$ 3,663**	$ 2,467	**$ 9,287**	$ 8,474
Depletion per sales ($/boe)	**$ 7.32**	$ 7.70	**$ 7.32**	$ 7.84

DD&A expense decreased on a boe basis during the current reporting periods compared to the same periods of 2017. These lower depletion rates were due to the fourth quarter's recognition of a $17.1 million impairment charge against the carrying value of our development and production assets. They were also caused by an increase in the December 31, 2017 measure of our proved plus probable reserves. During the current reporting periods, higher production volumes offset these lower rates resulting in overall increases in DD&A compared to the same periods of 2017.

Deferred Customer Obligation Amortization

($ thousands)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Deferred customer obligation amortization	**$ (195)**	$ (363)	**$ (583)**	$ (363)

During the third quarter of 2017, a customer transferred a section of pipeline to us which connected our 12" Aitken Creek Pipeline, located in northeast BC, to the Alliance Pipeline. The estimated fair value of this connecting pipeline resulted in a deferred customer obligation which is being amortized over the term of the agreement, which expires October 31, 2020, pursuant to which we are contractually obligated to provide this customer with access to a portion of our Aitken Creek Pipeline.

Share-Based Compensation

($ thousands)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Share-based compensation	**$ 121**	$ 182	**$ 359**	$ 691

We estimated lower fair values for the share options and restricted awards granted during the year to date compared to previous years' grants. When combined with cancelled unvested awards caused by staffing reductions, this resulted in lower share-based compensation for the current reporting periods compared to the same periods of 2017.

Amortization of Flow-Through Common Shares Premium

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Amortization of flow-through common shares premium	**$ -**	$ -	**$ (323)**	$ -

During the year to date, we incurred the required $2.0 million of qualifying Canadian exploration expenditures pursuant to the December 2017 issuance of 6,450,000 common shares on a flow-through basis. As a result of incurring these exploration expenditures, during the year to date we amortized the associated $0.3 million flow-through common shares premium.

Gain on Dispositions of Properties

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Gain on dispositions of properties	**$ -**	$ -	**$ -**	$ (10,926)

The comparative period's gain was from the sale of certain assets located in the Knopcik/Pipestone and East Gold Creek areas of northwestern Alberta for net consideration of $17.8 million after customary closing adjustments.

Onerous Contract

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Onerous contract	**$ -**	$ 1,561	**$ -**	$ 1,561

During the comparative reporting periods, we recognized a $1.6 million non-cash charge resulting from the onerous portion of our Calgary head office lease contract (see "Onerous Contract and Indemnifications").

Financing Expenses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Interest & financing expense (income)	**$ 66**	$ (60)	**$ 152**	$ (184)
Accretion of provisions	**175**	177	**523**	515
Financing expenses	**$ 241**	$ 117	**$ 675**	$ 331

During the current reporting periods, we incurred interest & financing expenses compared to income in the same periods of 2017. The effective interest rates on drawn debt during the current reporting periods were 5.2% and 4.5%. Compared to the third quarter, we expect a decrease in the effective interest rate to 4.6% during the fourth quarter of 2018, including the recent 25 bps increase to our lender's prime rate. This expected decrease resulted from lower net debt relative to cash flows (defined under the section "Credit Facility"). The comparative periods' interest income resulted from cash-on-hand which subsequently financed our development, exploration and provision expenditures.

The accretion charges during the reported periods are comparable to one another because the effect from the current reporting periods' lower applied decommissioning obligations' discount rate was offset by a higher provision initially reported during the fourth quarter caused by the Birley/Umbach facility expansion from 25 mmcf/d to 50 mmcf/d.

Income Tax

We have not reported deferred tax assets because it is not probable that we can utilize our tax pools against future taxable profit. We had the following tax pools as at December 31, 2017:

($ thousands)	December 31 2017
Canadian oil & gas property expense	$ 849
Canadian development expense	48,821
Canadian exploration expense	54,653
Undepreciated capital costs	36,524
Net operating losses	274,500
Net capital loss	10,987
Other	1,871
Total	$ 428,205

Net & Comprehensive (Loss) Income

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	2018	2017	2018	2017
Weighted average shares outstanding - basic (thousands)	223,605	217,115	223,591	216,721
Dilutive impact of share-based awards (thousands)	-	-	-	423
Weighted average shares outstanding - diluted (thousands)	223,605	217,115	223,591	217,144
Net & comprehensive (loss) income	$ (1,944)	$ (3,923)	$ (6,513)	$ 4,246
Net (loss) income per share - basic & diluted ($/share)	$ (0.01)	$ (0.02)	$ (0.03)	$ 0.02

For the reported periods we reported net losses of $1.9 million and $6.5 million compared to a net loss of $3.9 million and net income of $4.2 million during the same periods of 2017. This lower third quarter net loss resulted from both significantly higher average commodity pricing and production volumes despite the absence of a $1.7 million realized gain on commodity price contracts as included in the comparative quarter. The year to date decrease in net income, despite higher average commodity pricing and production volumes, resulted from the absence of gains of $10.9 million and $3.7 million for property dispositions and commodity price contracts, respectively, as included in the comparative period.

Capital Resources, Capital Expenditures and Liquidity

We successfully completed a $2.0 million issuance of common shares on a flow-through basis during December 2017. We used these proceeds in the first quarter to finance the drilling of two (2.0 net) exploratory vertical Birley/Umbach wells. These vertical wells have further delineated our contiguous Montney resource, preserved Birley/Umbach undeveloped lands and confirmed the fair value of our exploration & evaluation assets.

Despite the previously reported significant increase in our December 31, 2017 proved and proved plus probable reserves, relative to the prior year, and having a highly unleveraged balance sheet, with recent decreases in forward natural gas benchmark pricing our lender reduced its availability of the demand credit facility from $18.0 million to $10.0 million upon its scheduled May 31, 2018 reassessment. The next scheduled October 31, 2018 reassessment is currently on-going. As at September 30, 2018, we had debt of $2.2 million. We are currently assessing the impact of the T-South Pipeline rupture on our 2018 exit net debt and drawn debt balances.

We will continue to focus on capital preservation and optionality until we observe more constructive BC Station 2 benchmark pricing or we are otherwise able to secure more favorable natural gas pricing. As a result, we may voluntarily shut-in volumes throughout the remainder of the year, as we did during October and November 2018, in response to commodity pricing. Although our current capital program is nominal, we believe that our prior capital programs which saw us drill and complete 13 (11.23 net) wells on our Birley/Umbach property as well as complete the Birley facility expansion to 50 mmcf/d puts us in an excellent position to accelerate activity when commodity prices recover.

Adjusted Funds Flow

($ thousands, except where noted)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Cash inflow (outflow) from operating activities	**$ 1,132**	$ (1,352)	**$ 633**	$ 3,483
Add back:				
Change in operating non-cash working capital	**809**	1,444	**2,001**	(997)
Provision expenditures	**231**	326	**1,013**	460
Exploration & evaluation expenses	**-**	66	**111**	261
Severance costs	**113**	163	**834**	671
Adjusted funds flow (1)	**$ 2,285**	$ 647	**$ 4,592**	$ 3,878
Per share - basic & diluted	**$ 0.01**	$ -	**$ 0.02**	$ 0.02

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Adjusted funds flow increased for the current reporting periods compared to the same periods of 2017 as a result of both higher production volumes and average commodity pricing. Further contributing to these increases were lower G&A and net production expense, on a boe basis. The adjusted funds flow increases were partially offset by modest realized losses from a commodity price contract during the current reporting periods compared to significant gains from similar contracts in the comparative periods. Our third quarter adjusted funds flow is the highest of the nine consecutive quarters we have reported positive adjusted funds flow which coincides with our transition to a Montney focused play.

Net Debt

($ thousands)	September 30 2018	December 31 2017
Debt	**$ (2,232)**	$ -
Cash	**-**	4,341
Accounts receivable	**4,249**	3,490
Prepaids & deposits	**1,546**	1,373
Accounts payable & accrued liabilities	**(4,276)**	(9,915)
Net debt (1)	**$ (713)**	$ (711)

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

We had net debt of $0.7 million at both September 30, 2018 and December 31, 2017. Net debt remained unchanged between these reported dates because year to date adjusted funds flow of $4.6 million was offset by development, provision, severance and exploration & evaluation expenditures. Net debt at September 30, 2018 decreased $1.9 million from June 30, 2018 as a result of $2.3 million of adjusted funds flow less $0.4 million of onerous contract provision and severance expenditures.

Credit Facility

As a result of the scheduled May 2018 semi-annual review, we amended our demand credit facility agreement with a Canadian chartered bank resulting in a revised availability of $10.0 million as at September 30, 2018 (the "Demand Credit Facility"). At December 31, 2017, the availability was $18.0 million. The Demand Credit Facility's next scheduled October 2018 semi-annual review is currently on-going. As at September 30, 2018, we had debt borrowings of $2.2 million and outstanding letters of credit of $0.9 million, as secured by our lender, which reduced the available Demand Credit Facility credit to $6.9 million (at December 31, 2017 – drawings of $nil, outstanding letters of credit of $0.8 million and available credit of $17.2 million).

All borrowings under the Demand Credit Facility have been classified as a current liability, as the lender can request repayment at any time of all outstanding drawn amounts. Changes in the availability in the Demand Credit Facility are possible, from one semi-annual review to the next, with draws in excess of availability becoming immediately payable. Borrowings incur interest at the prime rate plus an applicable margin and are collateralized by floating charges and security interests over all of our present and future properties and other assets. In addition, the Demand Credit Facility includes operating and financial restrictions on us that include restrictions on paying dividends or making other distributions in respect of our securities.

The Demand Credit Facility has financial covenants requiring that at each reporting period the adjusted working capital equals or exceeds a one to one ratio and that net debt to cash flows does not exceed a three to one ratio. For the purposes of these covenants:

- Adjusted working capital is defined as working capital excluding both the current portion of commodity price contracts and debt but including the undrawn portion of the Demand Credit Facility, and
- Net debt is defined as working capital but excluding the current portion of commodity price contracts and
- Cash flows are determined over the last 12 months and are defined as cash flows from operating activities before changes in non-cash working capital and excluding one-time costs.

As at the end of any month, if the greater of our net debt or the Demand Credit Facility draws are either up to $6.0 million or in excess of $6.0 million, within 60 days of the end of any such month, the terms of the Demand Credit Facility require that we enter into commodity price contracts covering no less than 30% or 50%, respectively, of our forecasted twelve month combined production volumes.

As at September 30, 2018, we were in compliance with the foregoing financial covenants and other requirements under the Demand Credit Facility.

Capital Expenditures

Our capital expenditures during the reported periods were as follows:

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Land & lease	**$ -**	$ 182	**$ 174**	$ 182
Drilling & completions	**-**	10,069	**2,100**	22,630
Facilities & equipment	**-**	4,318	**253**	8,393
Field expenditures	**-**	14,569	**2,527**	31,205
Capitalized G&A	**-**	164	**150**	586
Total	**$ -**	$ 14,733	**$ 2,677**	$ 31,791
Proceeds from dispositions	**$ -**	$ -	**$ -**	$ 17,838

During the year to date, we drilled two (2.0 net) vertical exploratory wells in the Birley/Umbach area for $2.1 million. These wells further delineated 20 gross (19.5 net) undrilled contiguous sections of Montney rights (located three kilometres north of our main Montney land block and eight kilometres from the nearest well drilled into the Montney), as we evaluated the pay thickness and reservoir quality throughout the entire 235 metre thick Montney zone. These vertical wells were funded by the proceeds from our December 2017 flow-through share issuance. These 20 gross sections of Montney mineral rights north of our main Montney land block include the two sections we secured during the year to date in addition to a third section acquired during the fourth quarter of 2018 ($0.15 million) that reinforce our land position adjacent to the two (2.0 net) aforementioned exploratory Birley/Umbach vertical wells.

Provisions

Decommissioning Obligations

At September 30, 2018, the net present value of our decommissioning obligations was $31.3 million which was slightly higher than $31.1 million at December 31, 2017. During the year to date, $0.3 million in decommissioning obligation expenditures was more than offset by accretion of $0.5 million which reflects the increase in the obligation associated with the passage of time. We estimate this net present value based on a total future undiscounted and uninflated liability of $31.9 million (December 31, 2017 - $31.7 million).

As at September 30, 2018 and December 31, 2017, the estimated obligations include assumptions in respect of actual costs to abandon wells and facilities or reclaim the property, the time frame in which such costs will be incurred, an annual inflation rate of 2.0% and an average risk-free interest rate of 2.2% used to calculate the obligations' future and present values, respectively.

Onerous Contract and Indemnifications

During the comparative reporting periods, we recognized a provision caused by the onerous portion of our Calgary head office lease contract. This provision represented the present value of the minimum future lease payments we are obligated to make under the estimated onerous portion of the non-cancellable lease contract less estimated recoveries. At September 30, 2018, the amount of these estimated future expenditures to settle this provision was $0.6 million. These estimated future expenditures will be incurred through to the Calgary head office lease expiry in June 2019 and were discounted using a risk-free discount rate of 2%.

We are also involved in litigation and claims arising from indemnifications provided to the buyer of our former Tunisian operations in 2014. At September 30, 2018, an estimate of probable future disbursements for these indemnifications, including professional costs, totaled $0.9 million.

Share Capital

Details of our outstanding share capital in addition to share options and restricted awards are as follows:

	September 30 2018	December 31 2017
Common shares outstanding	**223,604,601**	223,564,601
Share options	**13,299,032**	10,276,884
Restricted awards	**157,300**	200,370
Weighted average common shares - basic and diluted	**223,590,975**	217,173,649

As at November 7, 2018, we had 223,604,601 common shares, 13,299,032 share options and 127,300 restricted awards outstanding.

Off Balance Sheet Arrangements

We did not enter into any off balance sheet arrangements during the reported periods.

Outlook

In our second quarter MD&A, we provided guidance for the second half and full year 2018. This guidance included average production and net debt measures that will not be met as they are negatively impacted by the October 2018 rupture of one of the T-South Pipelines. Although the third party's T-South Pipelines are now back in-service, operating them at reduced pressures is expected to depress winter BC Station 2 pricing. We have reacted through voluntarily shutting-in our current production other than to meet our Chicago City Gate priced commitments. Because of the uncertainty on winter BC Station 2 pricing, at this time we are unable to provide updated guidance.

Quarterly Information from Operations

Summarized information by quarter for the two years ended September 30, 2018, appears below:

	Sept. 30 2018	Jun. 30 2018	Mar. 31 2018	Dec. 31 2017	Sept. 30 2017	Jun. 30 2017	Mar. 31 2017	Dec. 31 2016
Production Volumes								
Natural gas liquids (boe/d)	**707**	680	468	551	405	441	482	613
Natural gas (mcf/d)	**24,454**	22,253	13,806	19,240	14,109	19,065	18,022	21,548
Crude oil (bbl/d)	**24**	23	19	21	19	19	29	451
Average daily production (boe/d)	**4,807**	4,413	2,788	3,779	2,776	3,638	3,514	4,655
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 63.73**	$ 66.65	$ 58.35	$ 51.87	$ 42.07	$ 44.48	$ 51.39	$ 40.70
Average natural gas price ($/mcf)	**$ 1.54**	$ 1.40	$ 2.64	$ 0.99	$ 1.20	$ 2.77	$ 2.71	$ 3.31
Average oil price ($/bbl)	**$ 71.35**	$ 75.11	$ 68.34	$ 76.96	$ 51.49	$ 59.55	$ 60.32	$ 71.98
Operating Netback[1]								
Average commodity pricing ($/boe)	**$ 17.59**	$ 17.75	$ 23.35	$ 13.02	$ 12.61	$ 20.22	$ 21.42	$ 27.67
Royalty (expense) recovery ($/boe)	**$ -**	$ (0.07)	$ (0.17)	$ (0.08)	$ 0.52	$ (0.33)	$ 0.20	$ (2.84)
Realized (loss) gain on derivative contracts ($/boe)	**$ (0.17)**	$ 0.17	$ (1.18)	$ 3.83	$ 6.54	$ 1.01	$ 1.38	$ (0.35)
Net production expenses ($/boe)[1]	**$ (9.74)**	$ (10.17)	$ (14.84)	$ (11.06)	$ (12.32)	$ (11.82)	$ (11.27)	$ (11.88)
Operating netback ($/boe)[1][2]	**$ 7.68**	$ 7.68	$ 7.16	$ 5.71	$ 7.35	$ 9.08	$ 11.73	$ 12.59
Wells Drilled								
Exploratory wells (net)	**-**	-	2.00	-	-	-	-	-
Natural gas wells (net)	**-**	-	-	-	-	3.63	-	2.63
FINANCIAL ($ thousands, except per share amounts)								
Petroleum & natural gas revenues, net of royalties	**$ 7,778**	$ 7,098	$ 5,815	$ 4,499	$ 3,351	$ 6,583	$ 6,838	$ 10,631
Adjusted funds flow [1]	**$ 2,285**	$ 1,836	$ 471	$ 1,100	$ 647	$ 1,195	$ 2,036	$ 1,713
Per share - basic & diluted ($/share)	**$ 0.01**	$ 0.01	$ -	$ 0.01	$ -	$ 0.01	$ 0.01	$ 0.01
Cash inflow (outflow) from operating activities	**$ 1,132**	$ 1,223	$ (1,722)	$ 2,635	$ (1,352)	$ 6,280	$ (1,445)	$ (1,517)
Net (loss) income[3]	**$ (1,944)**	$ (2,471)	$ (2,098)	$ (21,160)	$ (3,923)	$ (2,253)	$ 10,422	$ 6,427
Per share - basic & diluted ($/share)	**$ (0.01)**	$ (0.01)	$ (0.01)	$ (0.10)	$ (0.02)	$ (0.01)	$ 0.05	$ 0.03
Capital expenditures	**$ -**	$ 180	$ 2,497	$ 7,253	$ 14,733	$ 8,235	$ 8,823	$ 4,177
Net (debt) surplus[1]	**$ (713)**	$ (2,654)	$ (3,961)	$ (711)	$ 3,616	$ 18,294	$ 25,622	$ 15,138
Total assets	**$ 120,572**	$ 123,637	$ 127,227	$ 130,571	$ 155,799	$ 144,891	$ 148,665	$139,975
Common Shares (thousands)								
Weighted average during period - basic	**223,605**	223,603	223,565	218,517	217,115	216,598	216,443	216,443
Weighted average during period - diluted	**223,605**	223,603	223,565	218,517	217,115	216,598	216,900	216,621
Outstanding at period end	**223,605**	223,605	223,565	223,565	217,115	217,115	216,443	216,443

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.
(2) May not be additive due to rounding.
(3) Includes $17.1 million and ($10.9 million) in impairment charges (net reversal) against (towards) properties for the three months ended December 31, 2017 and December 31, 2016, respectively.

Factors That Have Caused Variations over the Quarters

The factors described below only apply to the quarterly information presented above.

Generally, the quarterly changes in operating and financial measures since the first quarter of 2017, in comparison to the fourth quarter of 2016, result from previous Alberta assets which, during 2016, were either sold or as included in a share distribution. Beginning in the first quarter of 2017, our operating and financial results reflect the completion of our transition to a Montney play focused company. Upon transition, production trended with our Birley/Umbach property including this area's 2016 and 2017 development programs which added seven (6.27 net) horizontal wells, of which five (4.27 net) came on-stream throughout 2017 with the remaining two (2.00 net) coming on-stream during the first quarter. However, during the second half of 2017 and first half of 2018, extended third party restrictions did not allow us to demonstrate our production potential. Although our third quarter production volumes were relatively unaffected by third party constraints, during the fourth quarter of 2018 further restrictions caused by a rupture on one of the T-South Pipelines will affect this period's production volumes.

Beginning in the first quarter of 2017, on transition to a Montney focused natural gas company, our realized commodity prices began trending with the BC Station 2 benchmark. Changes in our petroleum and natural gas revenues, net of royalties and adjusted funds flow have trended with the BC Station 2 and Western Canadian Select benchmark prices and volumes. During 2017, our net surplus has generally trended down as our capital expenditures incurred on development and exploration of our Birley/Umbach area exceeded our adjusted funds flow ultimately resulting in us reporting net debt. Since the first quarter, our adjusted funds flow has exceeded our capital expenditures resulting in us reporting lower measures of net debt.

Please refer to other sections of this MD&A for detailed discussions on variations during the comparative quarters and to our previously issued interim and annual management's discussion and analysis for changes in prior quarters.

Risk Factors

Investors should carefully consider the risk factors set out in our AIF and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out in our AIF are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally. If any of the these risks or other risks occur, our business, prospects, financial condition, results of operations and cash flows could be adversely affected in a material way.

Additional information on risks, assumptions and uncertainties are found under the heading "Forward-Looking Statements".

Adopted New Accounting Standards

The Interim Financial Statements were prepared following the same accounting policies as summarized in note 3 in the Audited Financial Statements, except the policies for financial instruments and revenue recognition. These policies were respectively replaced upon the January 1, 2018 retroactive adoptions of IFRS 9 "Financial Instruments" and IFRS 15 "Revenue from Contracts with Customers". IFRS 9 replaced the multiple classification and measurement models for financial assets with a single model that has three classifications categories: amortized cost, fair value through profit or loss and fair value through other comprehensive income. IFRS 15 provides a five-step model which includes identifying performance obligations. These adopted new accounting standards are detailed in note 3 to the Interim Financial Statements. The adoption of these standards did not have a material impact on the Interim Financial Statements.

Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to us is made known to our CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICOFR") to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in our ICOFR were identified during the period beginning on July 1, 2018 and ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect our ICOFR.

We have designed our ICOFR based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

It should be noted that a control system, including our disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Other Information

Non-GAAP Measures

The following non-GAAP measures do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

- Adjusted funds flow is calculated from cash flow from operations adjusted for changes in non-cash operating working capital, exploration and evaluation expenses, provision expenditures and severance costs. We believe that adjusted funds flow (outflow) is a key measure to assess our ability to finance capital expenditures and when debt is drawn, to finance debt repayments. Adjusted funds flow is not intended to represent cash flow from operating activities, net income (loss) or other measures of financial performance calculated in accordance with IFRS and should not be construed as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of our financial performance. Adjustments to cash flow from operations are for changes in non-cash operating working capital which are expected to reverse and for those costs that are not directly caused by lifting production volumes.

- Net debt is calculated as debt adjusted for current assets less current liabilities as they appear on the balance sheets, both of which exclude mark-to-market commodity price contracts and assets and liabilities held for sale and current liabilities excludes any current portion of debt, deferred customer obligations and provisions. We use net debt to assist us in understanding our liquidity at specific points in time. We exclude the current portion of provisions and the deferred customer obligation as they are not financial instruments. Mark-to-market commodity contracts and assets and liabilities held for sale are excluded as they are unrealized.

- Operating netback is calculated as a period's sales of petroleum and natural gas, net of realized gains or losses on commodity price contracts, royalties and net production expenses, divided by the period's sales volumes. We use this non-GAAP measure to assist us in understanding our production profitability relative to current and fixed commodity prices and it provides an analytical tool to benchmark changes in field operational performance against prior periods. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms such as net income determined in accordance with IFRS as a measure of performance.

- Net production expense is calculated as production and operating expense less processing and gathering revenues. We use net production expense to determine the period's cash cost of operating expenses and net production expense per boe is used to measure operating efficiency on a comparative basis. This measure approximates our operating costs relative to only our volumes by excluding the approximated operating costs resulting from third party processing and gathering services.

Forward-Looking Statements

In the interest of providing our shareholders and readers with information regarding our company, including management's assessment of our future plans and operations, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: that the Oak Pipeline permanent replacement will be completed during the first half of 2019, that the T-South Pipeline will operate at reduced pressure and this will continue to depress BC Station 2 pricing, that we forecast minimal BC crown royalties through the remainder of 2018 and into 2019, that we anticipate that although there will be a decrease in our overall production expense that it be higher on a boe basis for the remainder of 2018, that our rent costs will significantly decrease upon the expiration of our office lease in mid-2019, that we expect a decrease in our next quarter's effective interest rate to 4.6%, the anticipated reduction in expenses resulting from head-count reductions and the suspension of an employee benefit program, that we will continue to focus on capital preservation and optionality until BC Station 2 benchmark pricing improves or we are otherwise able to secure more favorable natural gas pricing, that our previous capital program has put us in an excellent position to accelerate activity when commodity prices recover, that our future production will benefit from the commissioning of our Birley facility expansion, that our Aitken Creek Pipeline provides us optionality upon the future development of a gas plant, that we could secure further commodity marketing contracts, that TCPL's North Montney expansion will be completed in 2019 or 2020, the estimated effects on our operations caused by the rupture of one of the T-South Pipelines, how we intend to manage our company and that we may voluntarily shut-in volumes throughout the year when warranted by commodity prices.

With respect to the forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: that we will continue to conduct our operations in a manner consistent with that expressed herein, no significant future capital expenditure levels, future oil and natural gas prices, future oil and natural gas production levels, future currency, exchange and interest rates, our ability to obtain equipment in a timely manner to carry out exploration and development activities, the ability of the operator of the projects in which we have an interest in to operate in the field in a safe, efficient and effective manner, the impact of increasing competition, field production rates and decline rates, anticipated production volumes, our ability to replace and expand production and reserves through exploration and development activities, certain cost assumptions, that the budgeted capital program for the remainder of 2018, which is subject to the discretion of our Board of Directors, will not be amended in the future, and the continued availability of adequate debt and cash flow to fund our planned expenditures. Although we believe that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, anticipated third party restrictions, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, our Board of Directors may amend the capital program for the remainder of 2018 based on its discretion; environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increases in or unforeseen capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Future Oriented Financial Information

This MD&A may contain Future Oriented Financial Information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by our management to provide an outlook of our activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed under the heading "Forward-Looking Statements" and assumptions with respect to production rates and commodity prices. The actual results of our operations and the resulting financial results may vary from the amounts set forth herein, and such variation may be material. Our management believes that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments.

Selected Definitions and Abbreviations

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrels	mcf	thousand cubic feet
bbl/d	barrels per day	mmcf	million cubic feet
NGLs	natural gas liquids	mcf/d	thousand cubic feet per day
		mmcf/d	million cubic feet per day
		mmbtu	million British Thermal Units
		mmbtu/d	million British Thermal Units per day
		GJ	gigajoules
		GJ/d	gigajoules per day

Other	
boe	barrel of oil equivalent on the basis of 6 mcf/1 boe for natural gas and 1 bbl/1 boe for crude oil and natural gas liquids (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
mboe	1,000 barrels of oil equivalent
Canadian Light Sweet	Central market point for Canadian crude oil
Station 2	Market point for BC natural gas
AECO	Central market point for Canadian natural gas
Chicago City Gate	Market point for eastern US natural gas

Barrels of Oil Equivalent

Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.