Q1 2019

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 months ended March 31, 2019 and 2018 and should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes as at and for the three months ended March 31, 2019 and 2018 (the "Interim Financial Statements) and the audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2018 and 2017 (the "Audited Financial Statements). This MD&A is based on information available at May 9, 2019.

The term "first quarter" or similar terms are used throughout this document and refer to the three months ended March 31, 2019. The term "same quarter of 2018" or similar terms are used throughout this document and refer to the three months ended March 31, 2018. The term "reported quarters" or similar terms are used throughout this document and refer to both the three months ended March 31, 2019 and 2018, in this respective order. The term "fourth quarter" or similar terms are used throughout this document and refer to the three months ended December 31, 2018.

This MD&A contains measures ("non-GAAP") which are not prescribed by International Financial Reporting Standards ("IFRS") and, therefore, may not be comparable with the calculations of similar measures presented by other companies including those in the oil and natural gas industry. 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, 2018 ("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 period have been reclassified to conform to the current reporting period's 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 March 31	2019	2018
OPERATIONS		
Production [1]		
Natural gas liquids (boe/d)	**455**	468
Natural gas (mcf/d)	**15,389**	13,806
Crude oil (bbl/d)	**9**	19
Average daily production (boe/d) [2]	**3,029**	2,788
Sales Prices		
Average natural gas liquids price ($/boe)	**$ 49.96**	$ 58.35
Average natural gas price ($/mcf)	**$ 2.10**	$ 2.64
Average oil price ($/bbl)	**$ 57.89**	$ 68.34
Operating Netback [3]		
Average commodity pricing ($/boe)	**$ 18.34**	$ 23.35
Royalty expense ($/boe)	**$ (0.04)**	$ (0.17)
Realized loss on commodity price contract ($/boe)	**$ (1.69)**	$ (1.18)
Net production expense ($/boe) [3]	**$ (11.28)**	$ (14.84)
Operating netback ($/boe) [2] [3]	**$ 5.33**	$ 7.16
Wells Drilled		
Exploratory wells (net)	**-**	2.00
FINANCIAL ($ thousands, except per share amounts)		
Petroleum & natural gas revenues, net of royalties	**$ 4,991**	$ 5,815
Cash outflow from operating activities	**$ (157)**	$ (1,722)
Adjusted funds flow [3]	**$ 194**	$ 471
Per share - basic & diluted ($/share)	**$ -**	$ -
Net loss	**$ (2,496)**	$ (2,098)
Per share - basic and diluted ($/share)	**$ (0.01)**	$ (0.01)
Capital expenditures	**$ -**	$ 2,497
Net debt [3]	**$ 3,120**	$ 3,961
Total assets	**$ 97,022**	$ 127,227
Common Shares (thousands)		
Weighted average during period		
Basic & diluted	**223,642**	223,565
Outstanding at period end	**223,655**	223,565

(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.

Operating and Financial Results

Petroleum and Natural Gas Production Volumes

Three months ended March 31	2019	2018
Natural gas liquids (boe/d)	455	468
Natural gas (mcf/d)	15,389	13,806
Crude oil (bbl/d)	9	19
Total (boe/d)	3,029	2,788

During the first quarter our production increased by 241 boe/d compared to the same quarter of 2018. Despite this increase, both reported quarters were largely effected by production restrictions. Since being repaired in November 2018 following a rupture, Enbridge has operated its natural gas T-South Pipelines (“T-South Pipelines”) at reduced pressures which has limited throughput capacity during the winter season. Because take away volumes were limited from BC, it had an unfavorable effect on the first quarter’s BC Station 2 benchmark price. To limit natural gas volumes sold at this benchmark, we voluntarily restricted our production throughout the first quarter except to fulfill, when we could, natural gas fixed price contracts or contracts benchmarked to either the Chicago City Gate or Alliance Trading Pool (“ATP”).

In addition to Enbridge continuing to operate its T-South Pipelines at reduced operating pressures, starting on January 2, 2019, there was an unplanned outage at the Enbridge McMahon Gas Plant (“McMahon Plant”) that continued through to January 20, 2019. During this unplanned outage period we were forced to restrict our production. We began to ramp-up our production on January 23, 2019. Excluding this involuntary 20 day restricted period that partially prevented us from realizing peak winter pricing, but including voluntary production restrictions to limit exposure to the BC Station 2 benchmark, our first quarter production would have approximated 3,900 boe/d.

As reported, production restrictions also effected the first quarter of 2018. This included integrity and maintenance issues on a portion of Enbridge’s Oak 16” gathering line (the “Oak Pipeline”). This portion of the Oak Pipeline was permanently replaced during the first quarter.

Our first quarter production volumes increased 6% compared to the 2,856 boe/d reported during the fourth quarter. As already alluded, both the first and fourth quarters were effected by voluntary restrictions to limit natural gas volumes sold at depressed BC Station 2 pricing precipitated by the T-South Pipelines’ capacity constraints. Although the first quarter production volumes were also affected by the previously discussed McMahon Plant unplanned outage, to limit exposure to the BC Station 2 benchmark we entered into additional short-term natural gas contracts that provided us additional take away capacity, compared to the fourth quarter, at either fixed prices or at the ATP benchmark.

As a BC operator producing natural gas and its associated liquids, we are unaffected by the Government of Alberta’s imposed production curtailment of crude oil that went into effect on January 1, 2019.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended March 31		2019		2018
($ thousands, except per unit amounts)				
Natural gas liquids sales	$	2,047	$	2,458
$/boe		49.96		58.35
Natural gas sales	$	2,908	$	3,283
$/mcf		2.10		2.64
Oil sales	$	46	$	117
$/bbl		57.89		68.34
Petroleum & natural gas revenue	$	5,001	$	5,858
$/boe		18.34		23.35

Despite a modest increase in our production, our petroleum and natural gas revenue for the first quarter decreased compared to the same quarter of 2018. This decrease is because of lower overall realized pricing caused by a variety of reasons. These reasons, as further elaborated throughout this MD&A, include changes in various commodity benchmarks, entering into fixed price natural gas contracts, incurring higher pipeline tariffs to obtain additional take away capacity priced at various benchmarks other than BC Station 2, being partially unable to realize peak winter pricing caused by the unplanned outage at the McMahon Plant and a lower condensate yield from our natural gas production.

Our average commodity price during the first quarter decreased 7% from the $19.72/boe realized during the fourth quarter. Despite an increase in petroleum pricing and a comparable condensate yield from our natural gas production, this decrease was due to the other reasons as previously explained.

Our first quarter realized natural gas price was supported by our efforts to limit exposure to the BC Station 2 benchmark through finding take away capacity at either fixed prices or priced at various other benchmarks, albeit with higher associated pipeline tariffs. Although we are optimistic that the BC Station 2 benchmark will continue to improve including an increase of 96% during the first quarter from the fourth quarter average of $0.67/mcf, through our efforts we continue to realize a premium relative to this benchmark.

Benchmark Prices

Three months ended March 31	2019	2018
Natural gas liquids		
Canadian light sweet (1) ($/bbl)	$ 66.53	$ 72.08
Natural gas		
BC Westcoast Station 2 (2) ($/mcf)	$ 1.31	$ 1.91
Alliance Trading Pool (3) ($/GJ)	$ 2.63	$ 2.42
Chicago City Gate (4) (US$/mcf)	$ 3.32	$ 3.27

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

NGL Pricing

During the first quarter, consistent with the directional change in Canadian light sweet oil and various other liquids and condensate benchmarks, our realized NGL pricing of $49.96/boe decreased compared to the same quarter 2018. 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 decreased to 75% for the first quarter from 85% for the same quarter of 2018. This lower ratio was due to benchmark pricing for condensates decreasing at a greater rate than the decrease in the Canadian light sweet benchmark. Our condensate yield decreased during the first quarter compared to the same quarter of 2018 when we initially benefited from flush production after bringing on-stream 2.0 (2.0 net) Birley/Umbach wells. This also contributed to lowering both our realized NGL price and its ratio relative to the Canadian light sweet oil benchmark.

Our new NGL pricing contracts commenced on either March 1, 2019 or April 1, 2019 and include the effect of lower propane through to condensate benchmark pricing. These lower benchmarks are attributed to a variety of reasons including an increase in supply from both Montney and other Western Canadian shale play producers, a lack of take-away capacity perpetuated by rail shippers focusing on longer-term crude oil contracts and a lower demand from bitumen producers whose own production was curtailed starting January 1, 2019, due to the Alberta Government imposing mandatory production curtailments in response to widening crude oil benchmark differentials.

Our realized NGL price increased 15% during the first quarter compared to the $43.56/boe realized price reported during the fourth quarter. This increase corresponds with the higher Canadian light sweet benchmark price as it began to recover after the fourth quarter's precipitous decrease caused by a lack of take away capacity resulting in widening crude oil benchmark differentials.

Natural Gas Pricing

Our realized natural gas price of $2.10/mcf during the first quarter decreased compared to the $2.64/mcf for the same quarter of 2018. Although this decrease corresponds to the lower Station 2 benchmark, it was actually caused by fixed price contracts, higher pipeline tariffs for additional take away capacity priced to limit exposure to the BC Station 2 benchmark and being partially unable to realize peak winter pricing caused by the previously discussed unplanned outage at the McMahon Plant.

During the first quarter we voluntarily restricted our natural gas production to limit exposure to the BC Station 2 benchmark. We also obtained additional take away capacity resulting in the majority of our first quarter natural gas production being sold at fixed prices or either Chicago City Gate or ATP benchmark prices, albeit with higher associated pipeline tolls. We have firm pipeline capacity benchmarked to the Chicago City Gate and ATP of approximately 5,425 GJ/d through to October 31, 2020 and 1,900 GJ/d through to October 31, 2019, respectively. Although our seasonal firm contracts have since expired, during the first quarter it resulted in a further 4,250 GJ/d and 1,900 GJ/d being sold at the Chicago City Gate and ATP benchmarks. We also entered into monthly fixed price contracts throughout the first quarter ranging from $1.45/GJ to $1.65/GJ for combined natural gas volumes averaging 4,500 GJ/d. As a result of these efforts, we sold 87% of our natural gas production during the first quarter at prices other than the BC Station 2 benchmark compared to 40% during the same quarter of 2018. Selling our natural gas production at either fixed prices or these various other benchmarks resulted in us realizing a premium compared to BC Station 2 pricing.

Our realized natural gas price decreased 19% during the first quarter compared to the $2.60/mcf realized natural gas price reported during the fourth quarter. This decrease was due to a lower Chicago City Gate benchmark price which then averaged US$3.63/mmbtu. Also contributing to the natural gas price decrease were fixed price contracts, higher pipeline tariffs to obtain additional take away capacity and being partially unable to realize peak winter pricing caused by the previously discussed unplanned outage at the McMahon Plant.

Royalties

Three months ended March 31	**2019**	2018
($ thousands, except where noted)		
Royalty expense (recovery)	**$ 10**	$ 43
Per sales ($/boe)	**$ 0.04**	$ 0.17
Percent of revenues (%)	**-**	1

We are reporting negligible royalties for all reported quarters. During 2017, we were granted royalty credits as part of BC's Infrastructure Royalty Credit Program (the "Infrastructure Program"). We have continued to receive additional credits since this initial grant. This program provides credits on our Birley/Umbach development only after sufficient crown royalties have been generated by specific wells. We recognized $0.2 million of these credits through a decrease to our royalties during the reported quarters. 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 2019 we are forecasting nominal BC crown royalties as a result of these credit programs. 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 production. 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 at the end of any fiscal quarter, 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.

Outstanding commodity price contracts are measured at their approximated fair value on the date of the financial statements. This estimated fair value is 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 reporting dates are recognized in the net loss as unrealized gains or losses on commodity price contracts. Realized gains or losses from these financial commodity price contracts are recognized in the net loss over the settlement term.

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

Three months ended March 31		2019		2018
($ thousands)				
Realized loss on commodity price contract	$	460	$	295
Unrealized loss (gain) on commodity price contracts		17		(151)
Loss on commodity price contracts	$	477	$	144
Realized loss on commodity price contract ($/boe)	$	(1.69)	$	(1.18)

During the reported quarters we realized losses on our Chicago City Gate price indexed contract, which expired at the end of the first quarter, because our contracted price of US$2.68/mmbtu was lower than this benchmark's average price. If we had included these losses in our natural gas revenues, we would have reported adjusted natural gas sale prices for the reported quarters of $1.77/mcf and $2.40/mcf compared to our reported prices of $2.10/mcf and $2.64/mcf.

Outstanding Commodity Price Contracts

As at March 31, 2019, our outstanding commodity price contracts had the following terms:

Contractual Term	Notional Volumes	Index and Company's Received Price
Natural gas swap		
October 1, 2019 to December 31, 2019	3,000 GJ/d	Westcoast Station 2 CAD$1.645/GJ
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
October 1, 2019 to December 31, 2019	3,000 mmbtu/d	NYMEX (1) US$2.25/mmbtu to US$3.68/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
October 1, 2019 to December 31, 2019	3,000 mmbtu/d	Price at Chicago = NYMEX (1) less US$0.125/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 crude oil swaps, with notional volumes of 120 bbl/d, secure the price we receive for our condensates. The combination of the NYMEX natural gas collars and differential swaps provide us a minimum and maximum price on various notional volumes to be sold at Chicago City Gate pricing. Over the contractual terms through to either September 30, 2019 or December 31, 2019, for purposes of our minimum commodity price contract requirement contained in our demand credit facility (see "Credit Facility"), our lender has given us credit for notional volumes of 6,000 mmbtu/d or 3,000 mmbtu/d, respectively, for the combination of the natural gas collars and differential swaps.

Mark-to-Market

At March 31, 2019, our crude oil swaps were in a $0.1 million asset position because forward WTI benchmark pricing had decreased relative to our contracted prices. Inversely, our natural gas commodity price contracts were in a $0.3 million liability position because the forward Chicago City Gate and NYMEX benchmarks had increased relative to our contracted prices. For those outstanding contracts last reported at December 31, 2018, forward pricing changed for both WTI and Chicago City Gate resulting in offsetting changes in our contracts' fair values at March 31, 2019. In addition, during the first quarter we also entered into a natural gas swap indexed to the BC Station 2 benchmark and a natural gas collar indexed to the Chicago City Gate and NYMEX benchmarks whose terms both commence on October 1, 2019. For these various benchmarks, forward average pricing estimated at March 31, 2019 was unchanged compared to their contracted prices. As a result of offsetting changes or the lack thereof, this resulted in a negligible first quarter unrealized loss.

Net Production Expense

Three months ended March 31	2019	2018
($ thousands, except where noted)		
Production & operating	$ 3,346	$ 4,011
Less:		
Processing & gathering revenues	(270)	(288)
Net production expense [1]	$ 3,076	$ 3,723
Net production expense ($/boe) [1]	$ 11.28	$ 14.84
Production expense ($/boe)	$ 12.27	$ 15.98

(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.

The overall production & operating expense, including on a boe basis, decreased during the first quarter compared to the first quarter of 2018. These decreases occurred despite production restrictions resulting from the rupture of one of the T-South Pipelines and associated depressed BC Station 2 benchmark pricing and the previously discussed unplanned outage at the McMahon Plant. Although certain production & operating costs are variable in nature, over a short duration such costs are unavoidable. For example, the McMahon Plant's billing during January was not lowered for their unplanned outage. Our current processing arrangement to have our natural gas processed at the McMahon Plant expires June 1, 2019. We are actively negotiating a new processing toll with Enbridge and other producers who have excess processing capacity at the McMahon Plant. The first quarter of 2018 overall production expense, including on a boe basis, was affected by both the previously discussed Oak Pipeline integrity and maintenance issues and higher labour and steamer costs to flow restricted volumes through extremely cold weather. These higher costs could have been avoided had our production been unimpeded. All of these restrictions had the effect of increasing fixed operating costs, on a boe basis, relative to total operating costs.

During both reported quarters, production from our Birley/Umbach area contributed to lowering the overall average production expense on a boe basis. Specifically, during the first quarter our Birley/Umbach area averaged a production expense of $9/boe compared to the overall reported production expense of $12.27/boe.

The majority of our processing & gathering revenues come from tolls applied to a customer's production that flows through our 12" Aitken Creek Pipeline which is directly connected to the Alliance Pipeline. Our Aitken Creek Pipeline commences at Martin Creek and then passes through our Birley lands. It 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. Additionally, we recently completed another transportation agreement for the partial use of our Aitken Creek pipeline. The agreement will commence on the initial delivery of gas, anticipated to be late 2019 or early 2020, and will continue for a minimum period of two years. Minimum annual gathering charges are approximately $1.6 million.

Operating Netback

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

Three months ended March 31	2019	2018
Per sales ($/boe)		
Average commodity pricing	$ 18.34	$ 23.35
Royalty expense	(0.04)	(0.17)
Realized loss on commodity price contract	(1.69)	(1.18)
Net production expense [1]	(11.28)	(14.84)
Operating netback [1]	$ 5.33	$ 7.16

(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 due to rounding.

Our operating netback decreased during the first quarter compared to the same quarter of 2018. Although we are reporting a net production expense that is lower by $3.56/boe, despite production restrictions, this netback decrease was caused by lower commodity pricing for reasons already explained. Also contributing to this netback decrease was a higher realized loss from a commodity price contract that has since expired.

Take-or-Pay and Other Losses

Three months ended March 31	2019	2018
($ thousands)		
Take-or-pay revenues	$ (1,545)	$ (1,003)
Take-or-pay expense	$ 1,899	$ 1,155
Other losses	$ 26	$ 46

Included in both take-or-pay contract revenues and expenses for the first quarter are the following cost mitigation programs:

- The revenue and expense of selling and purchasing, respectively, third party natural gas production to meet our firm volume commitments on various third party pipelines was necessitated by the unplanned outage at the McMahon Plant. Although we benefited from the purchase and sale of these third party volumes, the net cost after including the associated pipeline tariffs was $0.2 million. Although we cannot say with any certainty, we do not anticipate the need for this cost mitigation program during future reporting periods.
- The revenue and expense of selling and purchasing, respectively, third party NGL production to meet a take-or-pay processing agreement. The $0.2 million net cost during the first quarter is similar to the same quarter of 2018 although take-or-pay contracts' revenue and expense have both decreased because of lower firm commitments and a reduction in NGL pricing. We have partially mitigated our continued exposure to this fee at least through to the first quarter of 2020 under similar terms as previously reported. 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 March 31	2019	2018
($ thousands, except per unit amounts)		
G&A expense before recoveries	$ 1,229	$ 1,861
Recoveries	(349)	(690)
G&A expense	$ 880	$ 1,171
Per sales ($/boe)	$ 3.23	$ 4.67

For the current reporting periods and as implemented throughout 2018, we realized lower G&A expenses before recoveries including lower staffing costs due to a 40% headcount reduction, the suspension of an employee benefit program and reduced information system costs. We estimate the previous year's headcount reduction and suspension of an employee benefit program will result in annual G&A cost savings of approximately $1.4 million. We will also implement a reduced work week from May through to September 2019. Similar to last year, we estimate this will result in costs savings of $0.2 million.

On January 1, 2019, we adopted *IFRS 16, Leases* ("IFRS 16") (see "Adopted New Accounting Standard"). This new accounting standard resulted in our first quarter office rent payments of $0.6 million, which includes lease and non-lease components, being respectively reported as a $0.4 million reduction in our lease liabilities (see "Lease Liabilities") and a charge of $0.2 million to G&A expense before recoveries. This compares to the first quarter of 2018 where we incurred similar office rent payments but reported as a charge of $0.4 million to G&A expense before recoveries and a $0.2 million reduction in our onerous contract provision. As a result of adopting IFRS 16, despite similar office rent payments, G&A expense before recoveries decreased $0.2 million during the first quarter compared to the same quarter of 2018.

Subsequent to March 31, 2019, we signed a lease for new Calgary office space with a June 1, 2019 commencement date through to an initial expiry of August 31, 2022 but with our option to extend, under the same terms, to February 27, 2025. The estimated annual cost savings from this new lease are $2.0 million.

Partially offsetting the above decreases to G&A expense before recoveries 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 $0.3 million during the first quarter compared to the same quarter of 2018.

G&A on a boe basis also decreased during the first quarter compared to the same quarter of 2018 as a result of lower overall G&A expense described above combined with modestly higher production.

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

Three months ended March 31		**2019**		2018
($ thousands, except per unit amounts)				
Depletion, depreciation & amortization	**$**	**2,498**	$	2,220
Depletion per sales ($/boe)	**$**	**6.86**	$	7.16

As previously discussed, on January 1, 2019, we adopted IFRS 16 (see "Adopted New Accounting Standard"). During the first quarter this new accounting standard resulted in us reporting additional depreciation of $0.2 million against a right-of-use asset associated to our current Calgary office space. As we adopted this new accounting standard using a modified retrospective approach, there is no comparable depreciation expense in the same quarter of 2018. This resulted in the overall DD&A expense increase during the first quarter compared to the same quarter of 2018.

The modestly higher production volumes' effect on the overall depletion expense was mostly offset by a lower rate. This resulted in the overall depletion expense being only $0.1 million higher during the first quarter compared to the same quarter of 2018. The lower depletion rate was due to last year's impairment expense of $19.6 million that lowered the net carrying value of our development and production assets combined with a modest increase in the December 31, 2018 measure of our proved plus probable reserves.

Net Financing Costs

Three months ended March 31		**2019**		2018
($ thousands)				
Accretion of provisions	**$**	**173**	$	174
Interest on bank debt		**35**		-
Other financing costs, net of interest income		**10**		(12)
Net financing costs	**$**	**218**	$	162

During the first quarter, we incurred interest on bank debt at a 4.5% effective interest rate. We were undrawn on our bank debt during the comparative quarter. The comparative quarter's interest income resulted from cash-on-hand which was used to finance a portion of that quarter's development, exploration, provision and severance expenditures.

The accretion charges during the reported quarters are comparable because the effect from the first quarter's lower applied decommissioning obligations' risk-free discount rate was offset by a higher provision caused by a change in estimate initially reported during the fourth quarter.

As previously discussed, on January 1, 2019, we adopted IFRS 16 (see "Adopted New Accounting Standard"). Interest expense from lease liabilities included in our net financing costs during the first quarter was insignificant.

Deferred Customer Obligation Amortization

Three months ended March 31		**2019**		2018
($ thousands)				
Deferred customer obligation amortization	**$**	**(194)**	$	(194)

During a previously reported period, 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

Three months ended March 31		2019		2018
($ thousands)				
Share-based compensation	$	152	$	91

Despite a decrease in the number of share-based awards granted during the first quarter where each has a lower estimated fair value, share-based compensation increased compared to the same quarter of 2018. This increase was due to the absence of headcount reductions reported during the comparative quarter resulting then in the recognition of recoveries from cancelled unvested awards.

Severance Costs

Three months ended March 31		2019		2018
($ thousands)				
Severance costs	$	-	$	721

Severance costs incurred during the first quarter of 2018 related to staffing reductions resulting from a continuing assessment of our staffing requirements. Throughout 2018, we incurred a total of $0.8 million in severance costs that reduced our headcount by 40%.

Amortization of Flow-Through Common Shares Premium

Three months ended March 31		2019		2018
($ thousands)				
Amortization of flow-through common shares premium	$	-	$	(323)

During the comparative quarter, 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 comparative quarter we amortized the associated $0.3 million flow-through common shares premium.

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 estimate we had the following tax pools at December 31, 2018:

($ thousands)		December 31 2018
Canadian oil & gas property expense	$	1,137
Canadian development expense		34,864
Canadian exploration expense		54,653
Undepreciated capital costs		26,349
Net operating losses		296,364
Net capital loss		10,987
Other		3,266
Total	$	427,620

Net & Comprehensive Loss

Three months ended March 31		2019		2018
($ thousands, except where noted)				
Weighted average shares outstanding - basic & diluted (thousands)		223,642		223,565
Net & comprehensive loss	$	(2,496)	$	(2,098)
Net loss per share - basic & diluted ($/share)	$	(0.01)	$	(0.01)

For the first quarter we are reporting an increase in our net loss compared to the same quarter of 2018. Despite modestly higher natural gas production, this increased net loss was due to lower commodity pricing for reasons previously explained which included being partially unable to realize peak winter pricing caused by the unplanned outage at the McMahon Plant. The associated production restriction was further exacerbated as we had previously entered into incremental short-term firm volume pipeline commitments, with their associated tariffs, to deliver natural gas production at various benchmarks and fixed prices with the objective to limit exposure to the Station 2 benchmark. These firm volume pipeline tariffs during the unscheduled outage at the McMahon Plant, net of our mitigation efforts, caused an increase in our net take-or-pay cost. Also contributing to the increase in the net loss was a higher loss from commodity price contracts.

Capital Resources, Capital Expenditures and Liquidity

Our credit facility's next scheduled semi-annual review is May 2019. We expect our lender may reduce the availability of our $10 million credit facility given recent decreases in forward natural gas benchmark pricing. During the first quarter, our debt increased to $3.0 million as exacerbated by lower petroleum and natural gas revenues caused by restricted production stemming from the unplanned outage at the McMahon Plant combined with T-South Pipelines' capacity constraints and their associated effect on depressing the BC Station 2 benchmark. 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 2019, as we did during the first quarter, in response to weak 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 and our Birley facility expansion to 50 mmcf/d puts us in an excellent position to accelerate activity when commodity prices recover.

Adjusted Funds Flow & Cash Outflow from Operating Activities

Three months ended March 31		2019		2018
($ thousands, except where noted)				
Cash outflow from operating activities	$	(157)	$	(1,722)
Add back:				
Change in operating non-cash working capital		(345)		928
Provision expenditures		659		472
Exploration & evaluation expenses		37		72
Severance costs		-		721
Adjusted funds flow (1)	$	194	$	471
Per share - basic & diluted	$	-	$	-

(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.

Despite modestly higher production, adjusted funds flow for the first quarter decreased compared to the same quarter of 2018. This decrease is due to lower commodity pricing and increases in both the take-or-pay net expense and a realized loss from a commodity price contract. These effects were partially offset by lower production & operating and G&A expenses.

The cash outflow from operating activities decreased by $1.6 million during the first quarter compared to the same quarter of 2018. This favorable change is due to both a decrease in non-cash working capital and the absence of severance costs reported during the same quarter of 2018. Contributing to the first quarter's decrease in non-cash working capital was the return of a $1.0 million deposit that previously guaranteed seasonal firm volume pipeline capacity. This capacity has since expired.

Capital Expenditures

Our capital expenditures during the reported quarters were as follows:

Three months ended March 31	**2019**	2018
($ thousands)		
Land & lease	**$ -**	$ 174
Drilling & completions	**-**	2,100
Facilities & equipment	**-**	73
Field expenditures	**-**	2,347
Capitalized G&A	**-**	150
Total	**$ -**	$ 2,497
Proceeds from dispositions	**$ -**	$ -

Our focus during the first quarter, as it continues to be, is capital preservation. As a result, during the first quarter we did not incur any capital expenditures. During the first quarter of 2018, we drilled and logged two (2.0 net) exploratory vertical Birley/Umbach wells. During the remainder of 2018, these wells were also completed. The drilling and completion costs for these two (2.0 net) wells totaled $2.2 million. These wells further delineated 21 gross (20.5 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). These vertical wells, which also preserved undeveloped lands, were funded by the proceeds from our December 2017 flow-through share issuance. Each well encountered approximately 225 metres of total Montney thickness. The quality of the reservoir encountered, particularly in the top 75 metres of the Montney and as seen from wireline log data, had consistent hydrocarbon charged porosity. Each well was perforated to obtain pressure information. We have just finished abandoning these wells which satisfies our flow-through financing obligations.

Net Debt

($ thousands)	**March 31 2019**	December 31 2018
Debt	**$ (2,976)**	$ (2,361)
Accounts receivable	**2,667**	3,386
Prepaids & deposits	**1,244**	2,528
Accounts payable & accrued liabilities	**(4,055)**	(5,547)
Net debt [(1)]	**$ 3,120**	$ 1,994

(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 $3.1 million and $2.0 million at March 31, 2019 and December 31, 2018, respectively. Net debt increased between these reported dates because the first quarter's adjusted funds flow of $0.2 million was more than offset by expenditures that totaled $1.1 million and included both decommissioning obligations and lease payments (see "Adopted New Accounting Standard"). Prepaid rents associated with our current Calgary office space for $0.2 million was also reclassified as a right-of-use asset on adoption of IFRS 16 (see "Adopted New Accounting Standard"). This resulted in a January 1, 2019 decrease in our non-cash working capital and a corresponding increase in our net debt.

We normally manage expenditures not to exceed our annual adjusted funds flow. However, during the first quarter we incurred $0.7 million of decommissioning obligation expenditures which included abandonments of 2.0 (2.0 net) vertical wells. As previously discussed, these abandonments were necessary in order to satisfy our flow-through financing obligations. Also the first quarter's adjusted funds flow was lower than we expected because of the unplanned outage at the McMahon Plant that partially prevented us from realizing peak winter pricing in addition to us continuing to incur both firm volume pipeline tolls and production & operating costs in the absence of production.

Credit Facility

Our amended demand credit facility agreement with a Canadian chartered bank has an availability of $10.0 million at March 31, 2019 and December 31, 2018 (the "Demand Credit Facility"). The Demand Credit Facility's next scheduled semi-annual review is May 2019.

We expect our lender to reduce the availability of the Demand Credit Facility given recent decreases in forward natural gas benchmark pricing. While there is no certainty in the amount of the borrowing base redetermination, we expect that our debt borrowings in May 2019 will be less than the anticipated reassessed Demand Credit Facility's availability. At March 31, 2019, we had debt borrowings of $3.0 million and outstanding letters of credit of $0.9 million, as secured by our lender, which reduced the available Demand Credit Facility credit to $6.1 million (at December 31, 2018 – drawings of $2.4 million, outstanding letters of credit of $0.9 million and available credit of $6.7 million).

All borrowings under the Demand Credit Facility have been classified as a current liability, as the lender can request repayment of all outstanding drawn amounts at any time. Changes in the availability of 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. Because the lender's definition of cash flows includes lease payments, this measure, was unaffected by adopting IFRS 16 (see "Adopted New Accounting Standard"). As previously discussed, net debt did increase on adoption of IFRS 16 by $0.2 million as prepaid rents at December 31, 2018 were reclassified at January 1, 2019 from working capital to a right-of-use asset. This modest increase in net debt did not have a significant effect on our financial covenant compliance.

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,

- 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 less lease payments.

At the end of any fiscal quarter, 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.

At March 31, 2019, we were in compliance with the foregoing financial covenants and other requirements under the Demand Credit Facility. We currently have entered into commodity price contracts covering only 28%, relative to the 30% required minimum, of our forecasted twelve month combined production volumes. We have until May 30, 2019, to rectify this difference which we will coordinate with our lender's upcoming semi-annual review.

Lease Liabilities

On adoption of IFRS 16 (see "Adopted New Accounting Standard") we recognized $0.6 million of lease liabilities that mostly consist of our current Calgary head office space. Although there was an available optional short-term expedient because this lease expires in June 2019, we chose not to take this option because future leases for office space and their associated payments are expected to be reported under IFRS 16. The effect of discounting this liability at our incremental borrowing rate, estimated at 6% on adoption and throughout the first quarter, was insignificant because of the magnitude of this liability and its short remaining term. Lease payments during the first quarter totaled $0.4 million. At March 31, 2019, we are reporting $0.2 million of lease liabilities.

Provisions

Decommissioning Obligations

At March 31, 2019, the net present value of our decommissioning obligations was $31.9 million which was lower than $32.4 million at December 31, 2018. During the first quarter, a decrease of $0.5 million in decommissioning obligations resulted from $0.7 million of expenditures as partially offset by accretion of $0.2 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 $32.8 million (December 31, 2018 - $33.3 million).

As at March 31, 2019 and December 31, 2018, 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 2.1% used to calculate the obligations' future and present values, respectively.

Onerous Contract

On adoption of IFRS 16 (see "Adopted New Accounting Standard"), we applied a practical expedient that allowed us to decrease our current Calgary office space right-of-use asset by the associated onerous contract provision of $0.4 million last reported at December 31, 2018. As a result, on adoption of IFRS 16 and thereafter we no longer report an onerous contract provision associated with our current Calgary office space.

Indemnifications

We are also involved in litigation and claims arising from indemnifications provided to the buyer of our former Tunisian operations sold in 2014. At March 31, 2019 and December 31, 2018, an estimate of probable future disbursements for these indemnifications, including professional costs, totaled $0.9 million.

Outstanding Share Capital

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

	March 31 2019	December 31 2018
Common shares outstanding	**223,654,501**	223,604,601
Share options	**17,737,200**	13,177,200
Restricted awards	**77,400**	127,300
Weighted average common shares - basic and diluted	**223,594,409**	223,594,409

As at May 9, 2019, we had 223,682,001 common shares, 17,737,200 share options and 49,900 restricted awards outstanding.

Commitments and Guarantees

At March 31, 2019, we had the following unrecognized contractual payments without giving effect to any offsetting third party agreements, which are anticipated to reduce some of these amounts:

($ thousands)	**2019**	**2020**	**2010**	**Thereafter**	**Total**
Operating and transportation contracts	**$ 1,262**	**$ 888**	**$ 212**	**$ -**	**$ 2,362**

At March 31, 2019 and December 31, 2019, we had guaranteed a third party's pipeline commitment through issuing letters of credit of $0.9 million (see "Credit Facility") as secured by our lender. We have also guaranteed indemnifications provided by our wholly owned subsidiary to the buyer of our former Tunisian operations (see "Indemnifications").

Recognized Contractual Payments

At March 31, 2019, our recognized estimated contractual payments included accounts payable & accrued liabilities of $4.1 million, debt of $3.0 million (see “Debt”) and lease liabilities (see “Lease Liabilities”) of $0.2 million. With the exception of debt, presuming no significant changes in these estimates, these recognized contractual payments are expected to be paid within the next year as financed from accounts receivable, proceeds from potential asset dispositions and/or cash inflow from operating activities or any combination thereof. Debt is payable on demand if called by our lender or if they do not extend the term of our Demand Credit Facility during the next scheduled renewal dates of May 2019 and October 2019.

Off Balance Sheet Arrangements

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

Outlook

As BC natural gas price weakness continues related to export capacity constraints, we remain cautious in deploying further capital. Consequently, our capital program in 2019 will be minimal until such time as commodity prices improve to constructive levels. Our management and Board of Directors will make adjustments to the capital program in response to changing market conditions. We also expect the following to occur during 2019 or early 2020:

- **$1.6 million of annualized gathering revenues:** We continue to lever our existing assets and recently completed a transportation agreement for the partial use of our 12” Aitken Creek pipeline. The agreement will commence on the initial delivery of gas, anticipated to be early 2020, and will continue for a minimum period of two years. Minimum gathering charges will total approximately $1.6 million annually.

- **New processing contract:** Our current processing arrangement to have our natural gas processed at the McMahon Plant expires June 1, 2019. We are actively negotiating a new processing toll with Enbridge and other producers who have excess processing capacity at this plant.

- **Renewal of our credit facility:** Our credit facility’s next scheduled semi-annual review is May 2019. We expect our lender to reduce the $10 million availability of our credit facility given recent decreases in forward natural gas benchmark pricing. While there is no certainty in the amount of the borrowing base redetermination, we expect that our debt borrowings in May 2019 will be less than the anticipated reassessed credit facility’s availability. At March 31, 2019, we had debt borrowings of $3.0 million.

Quarterly Information from Operations

Summarized information by quarter for the two years ended March 31, 2019, appears below:

	Mar. 31 2019	Dec. 31 2018	Sept. 30 2018	Jun. 30 2018	Mar. 31 2018	Dec. 31 2017	Sept. 30 2017	Jun. 30 2017
Production Volumes								
Natural gas liquids (boe/d)	**455**	405	707	680	468	551	405	441
Natural gas (mcf/d)	**15,389**	14,641	24,454	22,253	13,806	19,240	14,109	19,065
Crude oil (bbl/d)	**9**	12	24	23	19	21	19	19
Average daily production (boe/d)	**3,029**	2,856	4,807	4,413	2,788	3,779	2,776	3,638
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 49.96**	$ 43.56	$ 63.73	$ 66.65	$ 58.35	$ 51.87	$ 42.07	$ 44.48
Average natural gas price ($/mcf)	**$ 2.10**	$ 2.60	$ 1.54	$ 1.40	$ 2.64	$ 0.99	$ 1.20	$ 2.77
Average oil price ($/bbl)	**$ 57.89**	$ 54.13	$ 71.35	$ 75.11	$ 68.34	$ 76.96	$ 51.49	$ 59.55
Operating Netback[1]								
Average commodity pricing ($/boe)	**$ 18.34**	$ 19.72	$ 17.59	$ 17.75	$ 23.35	$ 13.02	$ 12.61	$ 20.22
Royalty (expense) recovery ($/boe)	**$ (0.04)**	$ (0.14)	$ -	$ (0.07)	$ (0.17)	$ (0.08)	$ 0.52	$ (0.33)
Realized (loss) gain on derivative contracts ($/boe)	**$ (1.69)**	$ (2.59)	$ (0.17)	$ 0.17	$ (1.18)	$ 3.83	$ 6.54	$ 1.01
Net production expenses ($/boe)[1]	**$ (11.28)**	$ (14.01)	$ (9.74)	$ (10.17)	$ (14.84)	$ (11.06)	$ (12.32)	$ (11.82)
Operating netback ($/boe)[1][2]	**$ 5.33**	$ 2.98	$ 7.68	$ 7.68	$ 7.16	$ 5.71	$ 7.35	$ 9.08
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	**$ 4,991**	$ 5,146	$ 7,778	$ 7,098	$ 5,815	$ 4,499	$ 3,351	$ 6,583
Adjusted funds flow (outflow) [1]	**$ 194**	$ (413)	$ 2,285	$ 1,836	$ 471	$ 1,100	$ 647	$ 1,195
Per share - basic & diluted ($/share)	**$ -**	$ -	$ 0.01	$ 0.01	$ -	$ 0.01	$ -	$ 0.01
Cash (outflow) inflow from operating activities	**$ (157)**	$ (378)	$ 1,132	$ 1,223	$ (1,722)	$ 2,635	$ (1,352)	$ 6,280
Net loss [3]	**$ (2,496)**	$ (21,141)	$ (1,944)	$ (2,471)	$ (2,098)	$ (21,160)	$ (3,923)	$ (2,253)
Per share - basic & diluted ($/share)	**$ (0.01)**	$ (0.09)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.10)	$ (0.02)	$ (0.01)
Capital expenditures	**$ -**	$ 213	$ -	$ 180	$ 2,497	$ 7,253	$ 14,733	$ 8,235
Net (debt) surplus[1]	**$ (3,120)**	$ (1,994)	$ (713)	$ (2,654)	$ (3,961)	$ (711)	$ 3,616	$ 18,294
Total assets	**$ 97,022**	$ 101,416	$ 120,572	$ 123,637	$ 127,227	$ 130,571	$ 155,799	$144,891
Common Shares (thousands)								
Weighted average during period								
Basic and diluted	**223,642**	223,605	223,605	223,603	223,565	218,517	217,115	216,598
Outstanding at period end	**223,655**	223,605	223,605	223,605	223,565	223,565	217,115	217,115

(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 $19.6 million and $17.1 million in impairment charges against properties for the three months ended December 31, 2018 and 2017, respectively.

Factors That Have Caused Variations over the Quarters

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

Since our transition to a Montney play focused company, 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 of 2018. However, during the second half of 2017, first half of 2018 and the first quarter extended third party restrictions did not allow us to demonstrate our production potential. Production during the fourth and first quarters was also affected by the rupture on one of the T-South Pipelines. We then reacted to the resulting depressed BC Station 2 benchmark pricing by voluntarily shutting-in our production.

Our realized commodity prices normally trend 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. The previously described volume changes can shift the weighting of our natural gas production away from BC Station 2 and towards Chicago City Gate benchmark pricing or vice versa. During the second half of 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. From the first quarter of 2018 through to the third quarter of 2018, our adjusted funds flow exceeded our capital expenditures resulting in us reporting lower measures of net debt. Since then, this trend was interrupted by restricted volumes, an increase in our abandonment expenditures and a realized loss on a commodity price contract.

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 Standard

Except for the lease accounting policy, the Interim Financial Statements were prepared following the same accounting policies as summarized in note 3 in the Audited Financial Statements. This policy was replaced upon the January 1, 2019 modified retroactive adoption of IFRS 16. This approach does not require restatement of prior period financial information as it applies the standard prospectively. This standard replaced *IAS 17, Leases* ("IAS 17"). Under IAS 17, operating lease payments were expensed on a straight line basis over the lease term whereas under IFRS 16, there is an increased focus on control of the underlying asset. Under IFRS 16, when we have a contract that transfers substantially all the risks and rewards incidental to ownership of an identified asset, we recognize a lease liability equivalent to the present value of future fixed payments over the contract's non-cancellable term or longer if it is reasonably likely we will exercise an option to extend that term. These future fixed payments are discounted using our incremental borrowing rate if the rate implicit in the lease is not readily determinable. Mineral licenses and surface leases that allow for the extraction of petroleum and natural gas are not within the scope of IFRS 16.

On adoption of IFRS 16, right-of-use assets were initially measured at the amount equal to the lease liabilities but as adjusted by the amount of the prepaids & deposits relating to leases reported at December 31, 2018. We also relied on a practical expedient that the assessment of our current Calgary office space lease was onerous immediately before adopting IFRS 16 as an alternative to performing an impairment review. By choosing this practical expedient, we also decreased our right-of-use asset on adoption of IFRS 16 by the amount of the onerous contract provision reported at December 31, 2018. We measured the present value of our lease liabilities on adopting IFRS 16 using a discount rate of 6% as determined from our incremental borrowing rate. The adjustments to accounts measured at December 31, 2018 resulting from adopting IFRS 16 are as follows:

	As at December 31 2018	Adjustments	As at January 1 2019
Prepaids & deposits	$ 2,528	$ (244)	**$ 2,284**
Right-of-use assets	-	453	**453**
Lease liabilities	-	(599)	**(599)**
Provisions	(33,721)	390	**(33,331)**
Total	$ (31,193)	$ -	**$ (31,193)**

During the first quarter, IFRS 16 caused a decrease of $0.2 million in G&A expense before recoveries (see "G&A Expense") with an equivalent increase in DD&A (see "DD&A"). As a result, our adjusted funds flow increased $0.2 million whereas there was no change in our reported net loss. We also reported $0.4 million of fixed lease payments as applied against lease liabilities (see "Lease Liabilities"). The majority of the reported lease liabilities' amount is due to our current Calgary office space contract.

Future Adoption of Accounting Pronouncements

At the time of reporting, effective January 1, 2020 or thereafter there are no significant new accounting standards or amendments to existing standards issued by the International Accounting Standards Board nor are there any significant new interpretations issued by the International Financial Reporting Interpretations Committee that have not already been applied by us in preparing 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 January 1, 2019 and ended March 31, 2019 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

Management believes that the presentation of the following non-GAAP measures provides useful information to investors and shareholders as these measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis. 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 including those in the oil and natural gas industry:

- Adjusted funds flow (outflow) 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. Adjusted funds flow (outflow) per share is calculated as adjusted funds flow (outflow) divided by the period’s diluted shares. 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 (outflow) 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) surplus 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, provisions and lease liabilities. We use net (debt) surplus to assist us in understanding our liquidity at specific points in time. We exclude the current portion of deferred customer obligations, provisions and lease liabilities 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 we forecast minimal BC crown royalties through 2019, that although we cannot say with certainty, we do not anticipate the need in future reporting periods for our first quarter cost mitigation program of selling and purchasing third party natural gas production to meet our firm volume commitments, estimated additional G&A cost savings of approximately $1.4 million per year due to our 2018 headcount reduction and suspension of the employee benefit plan, estimated annual cost savings of $2.0 million as a result of our new office lease, that we expect our lender to reduce the availability of our $10.0 million credit facility during our semi-annual review in May 2019, however we expect our debt borrowing will be less than the anticipated reassessed facility's availability, 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 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 2019 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 2019, 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 2019 based on its discretion, there is no certainty in the amount of our borrowing base redetermination, 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

bbl	barrels
bbl/d	barrels per day
NGLs	natural gas liquids

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
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.