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2019

Management's Discussion and Analysis

CHINOOK energy inc

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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 six months ended June 30, 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 and six months ended June 30, 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 August 8, 2019.

The term "second quarter" or "year to date" are used throughout this document and refer to the three or six months ended June 30, 2019, respectively. The term "current reporting periods" is used throughout this document and refers to both the three and six months ended June 30, 2019, in this respective order. The term "same period(s) of 2018" or "comparative period(s)" or similar terms are used throughout this document and refer to the three or (and) six months ended June 30, 2018, depending on the 2019 period(s) under discussion. The term "reported periods" is used throughout this document and refers to both the three and six months ended June 30, 2019 and 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.

Future Operations and Liquidity

At June 30, 2019 we were not in compliance with one of our lender's financial covenants: *net debt to cash flow* (see "Credit Facility") that allows a maximum ratio of three times due to a cash flow deficit over the previous 12 months for the reasons set forth below. Cash flows, as defined by our lender, approximate adjusted funds flow less provision expenditures and lease payments. Third party outages and our reaction to depressed BC Station 2 pricing through voluntary restricting our production combined to reduce our adjusted funds flow over this previous period. Because this financial covenant is calculated on a trailing 12 months basis, the effect of these previous production restrictions are punitive in its calculation over the next forecasted nine months and outweigh the effect from expected higher pricing. Although our debt is drawn under a demand agreement resulting in all such draws always being classified as a current liability, the noncompliant *net debt to cash flow* financial covenant and recent decreases in forward BC natural gas strip pricing creates uncertainty as to the likelihood that our lender will provide us a waiver for the noncompliance with this financial covenant. At June 30, 2019, we had drawn $5.5 million from the demand credit facility and our lender had issued on our behalf $0.9 million of undrawn letters of credit that guarantee us certain transportation capacity on the Alliance Pipeline (at August 7, 2019, we had $5.7 million of drawn debt while undrawn letters of credit remain unchanged).

Our forecast may materially change if the BC Station 2 benchmark exceeds current strip pricing during the upcoming winter season resulting from the expected increase in BC take away capacity anticipated from the expansion of TCPL's North Montney Pipeline combined with the T-South Pipelines returning to normal operating pressures. We will continue to focus on capital preservation and optionality until we observe more constructive BC Station 2 benchmark pricing or are otherwise able to secure more favorable natural gas pricing.

While we continue discussions with our lender, the borrowing base redetermination and resolution of the financial covenant breach remain outstanding. These discussions include requesting that our lender provide us a waiver for the financial covenant breach and/or remove (modify) it from (within) the terms of our demand credit facility agreement. While these discussions are ongoing, we are evaluating other financing options that may inject additional liquidity including the disposition of natural gas assets, the sale/leaseback of midstream assets and other alternative sources of debt. Because no agreements have currently been reached, no assurance can be provided that any transaction will be concluded. Because of the general malaise in our industry, we do not view traditional financing options as currently being available. No assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that our lender will not call the debt as a result of the covenant breach. These material uncertainties may cast significant doubt with respect to our ability to continue as a going concern.

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. They have also been prepared on a going concern basis, which presumes we will continue our operations for the foreseeable future and will be able to realize our assets and discharge our liabilities and commitments in the normal course of business (see “Future Operations”). As a result, the Interim Financial Statements do not reflect adjustments and classifications of assets, liabilities, revenues and expenses which would be necessary if we were unable to continue as a going concern.

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 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 1610, 222 – 3rd Avenue S.W., Calgary, Alberta, Canada T2P 0B4.

Operating and Financial Highlights

	Three months ended June 30		Six months ended June 30	
	2019	2018	**2019**	2018
OPERATIONS				
Production (1)				
Natural gas liquids (boe/d)	**279**	680	**367**	575
Natural gas (mcf/d)	**8,457**	22,253	**11,904**	18,053
Crude oil (bbl/d)	**10**	23	**9**	21
Average daily production (boe/d) (2)	**1,698**	4,413	**2,360**	3,605
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 43.02**	$ 66.65	**$ 47.31**	$ 63.29
Average natural gas price ($/mcf)	**$ 1.38**	$ 1.40	**$ 1.84**	$ 1.87
Average oil price ($/bbl)	**$ 67.20**	$ 75.11	**$ 62.82**	$ 72.09
Operating Netback (3)				
Average commodity pricing ($/boe)	**$ 14.33**	$ 17.75	**$ 16.89**	$ 19.90
Royalty expense ($/boe)	**$ (0.22)**	$ (0.07)	**$ (0.11)**	$ (0.11)
Realized (loss) gain on commodity price contracts ($/boe)	**$ (0.89)**	$ 0.17	**$ (1.40)**	$ (0.35)
Net production expense ($/boe) (3)	**$ (17.26)**	$ (10.17)	**$ (13.44)**	$ (11.96)
Operating netback ($/boe) (2) (3)	**$ (4.04)**	$ 7.68	**$ 1.94**	$ 7.48
Wells Drilled				
Exploratory wells (net)	**-**	-	**-**	2.00
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 2,178**	$ 7,098	**$ 7,169**	$ 12,913
Cash (outflow) inflow from operating activities	**$ (1,940)**	$ 1,223	**$ (2,097)**	$ (499)
Adjusted funds (outflow) flow (3)	**$ (1,708)**	$ 1,836	**$ (1,514)**	$ 2,307
Per share - basic & diluted ($/share)	**$ (0.01)**	$ 0.01	**$ (0.01)**	$ 0.01
Net loss	**$ (22,242)**	$ (2,471)	**$ (24,738)**	$ (4,569)
Per share - basic and diluted ($/share)	**$ (0.10)**	$ (0.01)	**$ (0.11)**	$ (0.02)
Development and exploration expenditures	**$ -**	$ 180	**$ -**	$ 2,677
Net debt (3)	**$ 5,207**	$ 2,654	**$ 5,207**	$ 2,654
Total assets	**$ 77,284**	$ 123,637	**$ 77,284**	$ 123,637
Common Shares (thousands)				
Weighted average during period				
Basic & diluted	**223,681**	223,603	**223,662**	223,584
Outstanding at period end	**223,682**	223,605	**223,682**	223,605

(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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Natural gas liquids (boe/d)	**279**	680	**367**	575
Natural gas (mcf/d)	**8,457**	22,253	**11,904**	18,053
Crude oil (bbl/d)	**10**	23	**9**	21
Total (boe/d)	**1,698**	4,413	**2,360**	3,605

During the current reporting periods our production decreased by 2,715 boe/d and 1,245 boe/d compared to the same periods of 2018. The current reporting periods 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 especially during the peak demand winter season. Expectations are the T-South Pipelines will return to normal operating pressures sometime in November 2019. Because take away volumes were limited from BC, it had an unfavorable effect on the current reporting periods' BC Station 2 benchmark price. To limit natural gas volumes sold at this benchmark, we voluntarily restricted our production throughout the current reporting periods except to fulfill, when we could, contracts benchmarked to either the Chicago City Gate or Alliance Trading Pool ("ATP"). When we could not fulfil these contracts by delivering our own production because of various third party outages, we purchased and sold third party production as reported through the line items take-or-pay expenses and revenues, respectively (see "Take-or-Pay and Other Losses"). We continued to restrict our production throughout July 2019 but forecast sufficient natural gas price improvements by this upcoming September or October for our production to return to unrestricted levels of approximately 4,000 boe/d.

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. We began to ramp-up our production on January 23, 2019. This involuntary 20 day restricted period partially prevented us from realizing peak winter pricing. During the second quarter, there were also a total of 19 days of planned outages at either the McMahon Plant or on the Alliance Pipeline. During all of these outages we were forced to restrict our production and mitigate our firm volume processing and pipeline contracts.

Production restrictions also effected the comparative periods 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 three months ended March 31, 2019 (the "first quarter").

Our second quarter production volumes decreased 44% compared to the 3,029 boe/d reported during the first quarter. As already explained, the first half of 2019 was affected 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 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 second quarter where these bids were unsuccessful, at either fixed prices or at Chicago City Gate and ATP benchmark pricing.

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 June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2019**	2018	**2019**	2018
Natural gas liquids sales	**$ 1,092**	$ 4,127	**$ 3,139**	$ 6,585
$/boe	**43.02**	66.65	**47.31**	63.29
Natural gas sales	**$ 1,062**	$ 2,840	**$ 3,970**	$ 6,123
$/mcf	**1.38**	1.40	**1.84**	1.87
Oil sales	**$ 59**	$ 160	**$ 105**	$ 277
$/bbl	**67.20**	75.11	**62.82**	72.09
Petroleum & natural gas revenue	**$ 2,213**	$ 7,127	**$ 7,214**	$ 12,985
$/boe	**14.33**	17.75	**16.89**	19.90

Our petroleum and natural gas revenue for the current reporting periods decreased compared to the same periods of 2018. These decreases are because of both lower production volumes and overall realized pricing caused by a variety of reasons. These reasons, as further elaborated throughout this MD&A, include various lower benchmarks and incurring higher pipeline tariffs to obtain additional take away capacity to minimize our exposure to the BC Station 2 benchmark. Also contributing to the year to date decrease was being partially unable to realize peak winter pricing caused by the previously discussed unplanned outage at the McMahon Plant.

Our average commodity price during the second quarter decreased 22% from the $18.34/boe realized during the first quarter. This decrease was also due to various lower benchmarks despite an increase in our liquids' yield from our natural gas production resulting from a weighted average production shift toward our liquid rich Black/Martin properties. Further contributing to this decrease was the second quarter's absence of additional natural gas take away capacity at either fixed prices or at the Chicago City Gate benchmark that we reported during the first quarter.

Our current reporting periods' realized natural gas pricing were supported by our efforts to limit exposure to the BC Station 2 benchmark through voluntarily restricting production and finding take away capacity at various other benchmarks, albeit with higher associated pipeline tariffs. Although we are optimistic that the BC Station 2 benchmark will improve, through these efforts we continue to realize a premium relative to this benchmark.

Benchmark Prices

	Three months ended June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Natural gas liquids				
Canadian light sweet (1) ($/bbl)	**$ 73.83**	$ 80.58	**$ 70.18**	$ 76.33
Natural gas				
BC Westcoast Station 2 (2) ($/mcf)	**$ 0.60**	$ 1.11	**$ 0.95**	$ 1.51
Alliance Trading Pool (3) ($/GJ)	**$ 1.17**	$ 1.46	**$ 1.90**	$ 1.94
Chicago City Gate (4) (US$/mcf)	**$ 2.45**	$ 2.58	**$ 2.89**	$ 2.93

(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.

Natural Gas Liquids ("NGL") Pricing

During the current reporting periods, consistent with the directional change in Canadian light sweet oil and various other liquids and condensate benchmarks, our realized NGL pricing of $43.02/boe and $47.31/boe decreased compared to the same periods of 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 58% and 67% for the current reporting periods from 83% for the same periods of 2018. These lower ratios were due to our new NGL pricing contracts which included 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 Government of Alberta imposing mandatory production curtailments in response to widening crude oil benchmark differentials.

Our realized NGL price decreased 14% during the second quarter compared to the $49.96/boe realized price reported during the first quarter. This decrease is also due our new NGL pricing contracts that commenced in the second quarter which included the effect of lower propane through to condensate benchmark pricing as previously explained.

Natural Gas Pricing

Our realized natural gas prices during the current reporting periods was relatively comparable, albeit modestly lower, compared to the same periods of 2018 despite the precipitous drop in the BC Station 2 benchmark. These modest decreases, although contributed by lower BC Station 2 benchmark pricing, were also caused by higher pipeline tariffs for additional take away capacity priced to limit exposure to this BC benchmark. Also contributing to the modest year to date decrease was being partially unable to realize peak winter pricing caused by the previously discussed unplanned outage at the McMahon Plant.

During the current reporting periods we voluntarily restricted our natural gas production to limit exposure to the BC Station 2 benchmark. We have firm pipeline capacity benchmarked to the Chicago City Gate and ATP of approximately 5,425 GJ/d through to October 31, 2020, with our option to extend the term, and 1,900 GJ/d through to October 31, 2019, respectively. Although our additional firm and fixed price contracts have since expired, for the year to date it resulted in further natural gas production being sold at Chicago City Gate and ATP benchmarks and fixed prices ranging from $1.45/GJ to $1.65/GJ, albeit with higher associated pipeline tolls. As a result of these efforts, we sold 66% and 77% of our natural gas production during the current reporting periods at prices other than the BC Station 2 benchmark compared to 22% and 30% during the same periods 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 34% during the second quarter compared to the $2.10/mcf realized natural gas price reported during the first quarter. This decrease was due to lower BC Station 2, Chicago City Gate and ATP benchmark pricing which then averaged $1.31/mcf, US$3.32/mcf and $2.63/GJ, respectively. Although these are largely seasonal pricing decreases, volatility in Canadian natural gas benchmarks is also due to a lack of pipeline infrastructure to take more of Alberta and BC's natural gas production out of province. Also contributing to this natural gas price decrease was the absence in the second quarter of additional take away capacity and fixed price contracts as we had during the first quarter. This resulted in a weighted average shift of our realized natural gas price during the second quarter towards the relatively lower priced BC Station 2 benchmark.

Royalties

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Royalty expense	**$ 35**	$ 29	**$ 45**	$ 72
Per sales ($/boe)	**$ 0.22**	$ 0.07	**$ 0.11**	$ 0.11
Percent of revenues (%)	**2**	-	**1**	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 including a further grant during the second quarter for $0.2 million. This program provides credits on our Birley/Umbach development only after sufficient crown royalties have been generated by specific wells. Because our production has been restricted due to depressed BC Station 2 pricing during the current reporting periods, we only recognized $nil and $0.2 million of these credits through a decrease to our royalties compared to $0.3 million and $0.5 million during the same periods of 2018. 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 and depressed BC Station 2 strip pricing. 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 as unrealized gains or losses on commodity price contracts whereas realized gains or losses are recognized over their contractual term.

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

	Three months ended June 30		**Six months ended June 30**	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Realized loss (gain) on commodity price contracts	**$ 137**	$ (69)	**$ 597**	$ 226
Unrealized (gain) loss on commodity price contracts	**(210)**	737	**(193)**	586
(Gain) loss on commodity price contracts	**$ (73)**	$ 668	**$ 404**	$ 812
Realized (loss) gain on commodity price contract ($/boe)	**$ (0.89)**	$ 0.17	**$ (1.40)**	$ (0.35)

During the second quarter we realized a loss on our natural gas differential swap because our contracted price of NYMEX less US$0.435/mmbtu was lower than the Chicago City Gate benchmark. This loss was partially offset by our crude oil swap that secures the price we receive for our condensates because our contracted price of $84.20/bbl was higher than WTI. Both of these contracts expired at the end of the second quarter. We further realized losses during the year to date and its comparative period on a Chicago City Gate price indexed contract, which expired at the end of the first quarter, because the contracted price of US$2.68/mmbtu was lower than this benchmark's average price. For the comparative quarter we realized a gain on this contract. If we had included these realized losses in our natural gas revenues, we would have reported adjusted natural gas sale prices for the current reporting periods of $1.20/mcf and $1.57/mcf compared to our reported prices of $1.38/mcf and $1.84/mcf.

Outstanding Commodity Price Contracts

As at June 30, 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
January 1, 2020 to March 31, 2020	2,000 GJ/d	Westcoast Station 2 CAD$1.785/GJ
Natural gas collars		
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
January 1, 2020 to March 31, 2020	4,000 mmbtu/d	Chicago City Gate Monthly US$2.15/mmbtu to US$4.11/mmbtu
Natural gas differential swaps		
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		
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 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 June 30, 2019, our crude oil swap was in a $0.1 million asset position because forward WTI benchmark pricing had decreased relative to our contracted price of $84.00/bbl. Inversely, our natural gas commodity price contracts were in a $0.1 million liability position mostly because the forward Chicago City Gate benchmark had increased relative to our contracted prices of NYMEX less differentials. However, despite still being “out-of-the-money”, the unrealized gains during the current reporting periods include decreases in forward Chicago City Gate benchmark pricing.

Net Production Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Production & operating	**$ 2,967**	$ 4,324	**$ 6,313**	$ 8,335
Less:				
Processing & gathering revenues (1)	**(300)**	(241)	**(570)**	(529)
Net production expense (2)	**$ 2,667**	$ 4,083	**$ 5,743**	$ 7,806
Net production expense ($/boe) (2)	**$ 17.26**	$ 10.17	**$ 13.44**	$ 11.96
Production expense ($/boe)	**$ 19.20**	$ 10.77	**$ 14.78**	$ 12.78

(1) Processing & gathering revenues are included in the line item other revenues as found on the condensed consolidated statements of operations and comprehensive loss.
(2) 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.

Our overall production & operating expense decreased during the current reporting periods compared to the same periods of 2018 because of production restrictions caused by various third party outages or our reaction to depressed BC Station 2 benchmark pricing. Inversely, but for the same reasons, production expense on a boe basis increased over these same periods. This is because all of the production restrictions had the effect of increasing fixed operating costs, on a boe basis, relative to total operating costs. Unavoidable fixed costs can be significant and include, for example, contract operating fees, BC carbon taxes, operating insurance, municipal property taxes, firm processing tolls, mineral and surface lease costs. During the comparative periods 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.

During the second quarter we successfully negotiated an agreement to continue to have our natural gas processed at the McMahon Plant. This agreement expires in May 2020 and results in approximately a $1.50/boe increase in our operating costs.

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 as expected this upcoming winter season. 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 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 June 30		Six months ended June 30	
Per sales ($/boe)	**2019**	2018	**2019**	2018
Average commodity pricing	**$ 14.33**	$ 17.75	**$ 16.89**	$ 19.90
Royalty expense	**(0.22)**	(0.07)	**(0.11)**	(0.11)
Realized (loss) gain on commodity price contracts	**(0.89)**	0.17	**(1.40)**	(0.35)
Net production expense [1]	**(17.26)**	(10.17)	**(13.44)**	(11.96)
Operating netback [1]	**$ (4.04)**	$ 7.68	**$ 1.94**	$ 7.48

(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 netbacks decreased during the current reporting periods compared to the same periods of 2018. Given the extent of restrictions to limit our production sold at depressed BC Station 2 pricing, in addition to third party outages, the current reporting periods' operating netbacks are not representative of the profitability of our operations. These restrictions limited production to levels required by our firm pipeline capacity and processing contracts. The extent of these production restrictions also had the effect of increasing fixed operating costs, on a boe basis, relative to total operating costs. Also contributing to these netback decreases were lower average commodity prices mostly caused by our new NGL pricing contracts and higher realized losses from commodity price contracts that have since expired.

Take-or-Pay and Other Losses

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Take-or-pay revenues [1]	**$ (608)**	$ (985)	**$ (2,153)**	$ (1,988)
Take-or-pay expense	**$ 893**	$ 1,145	**$ 2,792**	$ 2,300
Other losses	**$ 69**	$ 42	**$ 95**	$ 88

(1) Take-or-pay revenues are included in the line item other revenues as found on the condensed consolidated statements of operations and comprehensive loss.

Included in both take-or-pay contract revenues and expenses for the current reporting periods 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 outages at either the McMahon Plant or on the Alliance Pipeline. Although we benefited from the purchase and sale of these third party volumes, the net cost after including the associated pipeline tariffs during the current reporting periods was $0.1 million and $0.3 million. Although we cannot say with any certainty, we do not anticipate future cost mitigation programs to be significant.
- The revenue and expense of selling and purchasing, respectively, third party NGL production was necessitated to meet a take-or-pay processing agreement. The $0.2 million and $0.3 million net cost during the current reporting periods compares to the same

periods of 2018 although take-or-pay contracts' revenues and expenses 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 June 30		Six months ended June 30	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
G&A expense before recoveries	**$ 1,023**	$ 1,364	**$ 2,252**	$ 3,225
Recoveries	**(286)**	(377)	**(635)**	(1,067)
G&A expense	**$ 737**	$ 987	**$ 1,617**	$ 2,158
Per sales ($/boe)	**$ 4.77**	$ 2.46	**$ 3.79**	$ 3.31

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 have also implemented 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 the year to date office rent payments of $0.8 million, which includes lease and non-lease components, being respectively reported as a $0.5 million reduction in our lease liabilities (see "Lease Liabilities") and a charge of $0.3 million to G&A expense before recoveries. Included in the same period of 2018 are similar office rent payments but reported as a charge of $0.5 million to G&A expense before recoveries and a $0.3 million reduction in our onerous contract provision. As a result of adopting IFRS 16, despite similar monthly office rent payments, G&A expense before recoveries decreased $0.2 million during the year to date compared to the same period of 2018.

During the second quarter we signed a lease for new Calgary office space that commenced on June 1, 2019 with an initial expiry of August 31, 2022 but with our option to extend, under the same terms, to February 28, 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 $0.1 million and $0.4 million during the current reporting periods compared to the same periods of 2018.

G&A on a boe basis increased during the current reporting periods compared to the same periods of 2018, despite decreases in overall G&A, as a result of lower production.

Impairment of Development & Production Assets

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Impairment of development & production assets	**$ 18,900**	$ -	**$ 18,900**	$ -

We identified evidence indicating impairment in the June 30, 2019 carrying value of our development and production assets. This evidence was a significant sustained reduction in forward BC Station 2 natural gas pricing. Further evidence were concerns about our ability to finance future development costs and the timing thereof (see "Future Operations and Liquidity"). As a result, on the June 30, 2019 carrying value, we tested for impairment on our one remaining Peace River Arch CGU. For the current reporting periods this test revealed impairment of $18.9 million.

The CGU's recoverable value of $62.5 million was estimated using a value-in-use calculation based on a roll forward of the December 31, 2018 independently prepared reserve report adjusted by us for the three engineering firms' average July 1, 2019 price forecasts, reserves produced during the year to date and deferring future development costs. We used this report's expected future net revenues anticipated to be produced from the combined reserve categories proved developed, proved undeveloped and probable reserves, using before income tax discount rates ranging from 10% to 20% depending on the reserve category, in addition to the following January 1, 2019 forward commodity price estimates (and their comparatives):

	Western Canadian Select ($/bbl) (1)		British Columbia Station 2 Natural Gas ($/mmbtu) (2)	
	June 30 2019 (3)	December 31 2018 (4)	**June 30 2019 (3)**	December 31 2018 (4)
2019	$ 59.41	$ 51.55	$ 0.98	$ 1.47
2020	$ 59.93	$ 59.58	$ 1.57	$ 1.99
2021	$ 62.82	$ 65.89	$ 2.12	$ 2.46
2022	$ 66.19	$ 68.61	$ 2.46	$ 2.81
2023	$ 69.30	$ 70.53	$ 2.61	$ 2.98
2024	$ 71.24	$ 72.34	$ 2.75	$ 3.11
Thereafter, increasing per year	2% to 3%	2%	2% to 4%	2%

(1) A market point for Canadian crude oil.
(2) A market point for Canadian natural gas.
(3) Source: Average of McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd. and Sproule Associates Limited price forecasts, effective July 1, 2019.
(4) Source: Average of McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd. and Sproule Associates Limited price forecasts, effective January 1, 2019.

Depletion, Depreciation and Amortization (“DD&A”) Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Depletion, depreciation & amortization	**$ 1,681**	$ 3,404	**$ 4,179**	$ 5,624
Depletion per sales ($/boe)	**$ 6.85**	$ 7.42	**$ 6.85**	$ 7.32

Lower production volumes and depletion rates resulted in depletion expense being $1.9 million and $1.8 million lower during the current reporting periods compared to the same periods of 2018. The lower depletion rates were due to last year’s impairment expense of $19.6 million that lowered the net carrying value of our development & production assets combined with a modest increase in the December 31, 2018 measure of our proved plus probable reserves.

As previously discussed, on January 1, 2019, we adopted IFRS 16 (see “Adopted New Accounting Standard”). During the current reporting periods this new accounting standard resulted in us reporting additional depreciation of $0.2 million and $0.4 million against right-of-use assets. As we adopted this new accounting standard using a modified retrospective approach, there is no comparable depreciation expense in the same periods of 2018. This partially offset the effects from lower production volumes and depletion rates, as previously discussed, resulting in a decrease to the overall DD&A expense during the current reporting periods compared to the same periods of 2018.

Financing Costs

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Accretion of provisions	**$ 174**	$ 174	**347**	348
Interest on bank debt	**45**	63	**$ 80**	63
Other financing costs	**18**	35	**28**	23
Financing costs	**$ 237**	$ 272	**$ 455**	$ 434

Our effective interest rates on bank debt were 4.5% and 4.0% during the current reporting periods compared to 4.0% for the same periods of 2018. As previously discussed, on January 1, 2019, we adopted IFRS 16 (see “Adopted New Accounting Standard”). Interest expense from lease liabilities included in our other financing costs during the current reporting periods was insignificant.

The accretion charges during the reported periods are comparable because the effect from the current reporting periods’ lower applied decommissioning obligations’ risk-free discount rate was offset by a higher provision caused by a change in estimate initially reported during the three months ended December 31, 2018.

Deferred Customer Obligation Amortization

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Deferred customer obligation amortization	**$ (195)**	$ (194)	**$ (389)**	$ (388)

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 June 30		Six months ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Share-based compensation	**$ 112**	$ 147	**$ 264**	$ 238

Despite a decrease in the number of share-based awards granted during the year to date where each has a lower estimated fair value, share-based compensation increased compared to the same period of 2018. This increase was due to the absence of headcount reductions reported during the comparative period resulting then in the recognition of recoveries from cancelled unvested awards. The second and comparative quarters were largely unaffected by such recoveries resulting in the expected decrease in share-based compensation.

Severance Costs

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Severance costs	**$ -**	$ -	**$ -**	$ 721

Severance costs incurred during the comparative year to date period 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 June 30		Six months ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Amortization of flow-through common shares premium	**$ -**	$ -	**$ -**	$ (323)

During the comparative year to date period, 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 then incurring these exploration expenditures, 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	**34,566**
Canadian exploration expense	**55,078**
Undepreciated capital costs	**26,349**
Net operating losses	**296,229**
Net capital loss	**10,987**
Other	**3,266**
Total	**$ 427,612**

The Government of Alberta's Bill 3, *Job Creation Tax Cut Act*, received Royal Assent during the second quarter. This will reduce the general Alberta corporate tax rate from 12% to 8% over the next four years. Because Chinook's head office is in Calgary, approximately one-half of any future corporate taxable income would be allocated to Alberta with the other half allocated to BC. These reduced tax rates lowered the value of our unrecognized deferred tax asset and the associated valuation allowance.

Net & Comprehensive Loss

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Weighted average shares outstanding - basic & diluted (thousands)	**223,681**	223,603	**223,662**	223,584
Net & comprehensive loss	**$ (22,242)**	$ (2,471)	**$ (24,738)**	$ (4,569)
Net loss per share - basic & diluted ($/share)	**$ (0.10)**	$ (0.01)	**$ (0.11)**	$ (0.02)

The net losses increased during the current reporting periods compared to the same periods of 2018. These increases are due to both lower production volumes and commodity pricing for reasons previously explained and an $18.9 million impairment charge against our development and production assets. To reiterate, during the year to date the lower commodity pricing includes 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 BC Station 2 benchmark. These firm volume pipeline tariffs during the unplanned outage at the McMahon Plant, net of our mitigation efforts, caused an increase in our net take-or-pay cost.

Capital Resources and Capital Expenditures

Adjusted Funds (Outflow) Flow & Cash (Outflow) Inflow from Operating Activities

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Cash (outflow) inflow from operating activities	**$ (1,940)**	$ 1,223	**$ (2,097)**	$ (499)
Add back:				
Change in operating non-cash working capital	**42**	264	**(303)**	1,192
Provision expenditures	**121**	310	**780**	782
Exploration & evaluation expenses	**69**	39	**106**	111
Severance costs	**-**	-	**-**	721
Adjusted funds (outflow) flow (1)	**$ (1,708)**	$ 1,836	**$ (1,514)**	$ 2,307
Per share - basic & diluted	**$ (0.01)**	$ 0.01	**$ (0.01)**	$ 0.01

(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 outflow for the current reporting periods increased compared to the inflows during the same periods of 2018. These increases are due to both lower production volumes and commodity pricing and increases in both take-or-pay net expense and realized losses from commodity price contracts. These effects were partially offset by lower overall production & operating and G&A expenses.

For the same reasons as just explained for adjusted funds outflow, cash outflow from operating activities increased during the current reporting periods compared to the same periods of 2018. The cash outflow from operating activities for the year to date benefited from both a decrease in operating non-cash working capital and the absence of severance costs reported during the same period of 2018. Contributing to this decrease in operating non-cash working capital was the return of a $1.0 million deposit that previously guaranteed additional firm volume pipeline capacity, which has since expired, less a $0.4 million deposit we recently posted to guarantee future processing tolls through the McMahon Plant.

Development and Exploration Expenditures

Our development and exploration expenditures during the reported periods were as follows:

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Land & lease	**$ -**	$ -	**$ -**	$ 174
Drilling & completions	**-**	-	**-**	2,100
Facilities & equipment	**-**	180	**-**	253
Field expenditures	**-**	180	**-**	2,527
Capitalized G&A	**-**	-	**-**	150
Total	**$ -**	$ 180	**$ -**	$ 2,677
Proceeds from dispositions	**$ -**	$ -	**$ -**	$ -

Our focus during the current reporting periods, as it continues to be, is capital preservation. As a result, during the current reporting periods we did not incur any capital expenditures. During the comparative year to date, 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)	**June 30 2019**	December 31 2018
Debt	**$ 5,489**	$ 2,361
Accounts receivable	**(1,412)**	(3,386)
Prepaids & deposits	**(1,825)**	(2,528)
Accounts payable & accrued liabilities	**2,955**	5,547
Net debt [(1)]	**$ 5,207**	$ 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 $5.2 million and $2.0 million at June 30, 2019 and December 31, 2018, respectively. Net debt increased between these reported dates because of the year to date adjusted funds outflow of $1.5 million and expenditures that also totaled $1.5 million which included both decommissioning obligations and lease payments (see "Adopted New Accounting Standard"). Prepaid rents associated with our previous 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.

Our ability to discharge our financial liabilities, as included in net debt, and fund our future operations is discussed within this MD&A under the "Future Operations and Liquidity" header.

We normally manage expenditures not to exceed our annual adjusted funds flow. However, during the year to date we incurred $0.8 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. For the year to date we are also reporting an adjusted funds outflow because of the various third party outages that partially prevented us from realizing peak winter pricing in addition to us continuing to incur both firm volume pipeline tolls and fixed production & operating costs in the absence of production combined with voluntary restrictions in response to depressed BC Station 2 pricing.

Credit Facility

Our amended demand credit facility agreement with a Canadian chartered bank had an availability of $10.0 million at June 30, 2019 and December 31, 2018 (the "Demand Credit Facility"). At June 30, 2019, we had debt borrowings of $5.5 million and undrawn letters of credit of $0.9 million, as secured by our lender, which reduced the available Demand Credit Facility credit to $3.6 million (at December 31, 2018 – drawings of $2.4 million, undrawn 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. 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.

At the end of any fiscal quarter, if we have either net debt or Demand Credit Facility draws, if the greater of the two is either below or in excess of $6.0 million, within 60 days we are required to enter into commodity price contracts covering no less than 30% or 50%, respectively, of our forecasted 12 months combined production volumes. At the date of this MD&A, we have entered into commodity price contracts covering only 28%, relative to the 30% required minimum, of our forecasted 12 months combined production volumes. We have until August 29, 2019, to rectify this difference.

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"). 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.

As previously discussed, at June 30, 2019 we were not in compliance with the *net debt to cash flow* financial covenant in the Demand Credit Facility that allows a maximum ratio of three times because we had cash outflows over the past 12 trailing months (see "Future Operations"). While we continue discussions with our lender, the borrowing base redetermination and resolution of the financial covenant breach remain outstanding. These discussions include requesting that our lender provide us a waiver for the financial covenant breach and/or remove (modify) it from (within) the terms of our demand credit facility agreement. No assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that our lender will not call the debt as a result of the covenant breach.

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 previous Calgary head office space. Although there was an available optional short-term expedient because this lease expired in June 2019, we chose not to take this option because our current Calgary office space and its associated payments are also captured under IFRS 16. The effect of discounting this liability at our incremental borrowing rate, estimated at 6% and 7.5% on adoption and at June 30, 2019, respectively, was insignificant because of the magnitude of this liability. Lease payments during the year to date totaled $0.5 million. At June 30, 2019, we are reporting $0.2 million of lease liabilities mostly associated with our current Calgary office space.

Provisions

Decommissioning Obligations

At June 30, 2019, the net present value of our decommissioning obligations was $33.4 million which was higher than $32.4 million at December 31, 2018. During the year to date, an increase of $1.0 million in decommissioning obligations resulted from a change in estimate caused by a decrease in the long-term risk-free interest rate and accretion which reflects the increase in the obligation associated with the passage of time as partially offset by expenditures. We estimate this net present value based on a total future undiscounted and uninflated liability of $32.9 million (December 31, 2018 - $33.3 million).

As at June 30, 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, respective annual inflation rates of 1.8% and 2.0% used to calculate the obligations' future value and respective average risk-free interest rates of 1.7% and 2.1% used to calculate the obligations' present value.

Onerous Contract

On adoption of IFRS 16 (see "Adopted New Accounting Standard"), we applied a practical expedient that allowed us to decrease our previous 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 previous 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 June 30, 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:

	June 30 2019	December 31 2018
Common shares outstanding	**223,682,001**	223,604,601
Share options	**17,612,200**	13,177,200
Restricted awards	**49,900**	127,300
Weighted average common shares - basic and diluted	**223,661,878**	223,594,409

As at August 8, 2019, we had 223,682,001 common shares, 17,312,200 share options and 49,900 restricted awards outstanding.

Commitments and Guarantees

At June 30, 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:

	2019	2020	2021	2022	2023	Thereafter	Total
Office contracts	$ 100	$ 321	$ 311	$ 304	$ 300	$ 350	$ 1,686
Operating and transportation contracts	1,742	1,789	220	-	-	-	3,751
	$ 1,842	**$ 2,110**	**$ 531**	**$ 304**	**$ 300**	**$ 350**	**$ 5,437**

The office contracts include the non-lease component of our current Calgary office space whereas the operating and transportation contracts relate to minimum contractual payments if we do not benefit from the operating services or pipeline transportation. The latter captures our most recent McMahon Plant processing agreement executed during the second quarter that expires on May 31, 2020.

At June 30, 2019 and December 31, 2018, we had guaranteed a pipeline commitment through undrawn letters of credit of $0.9 million (see “Future Operations and Liquidity” and “Credit Facility”) as secured by our lender. At June 30, 2019, we have guaranteed future processing tolls through a payment of $0.4 million as included in prepaids and deposits. We have also guaranteed indemnifications provided by our wholly owned subsidiary to the buyer of our former Tunisian operations (see “Indemnifications”).

Off Balance Sheet Arrangements

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

Outlook

We are uncertain about our ability to access sufficient capital to finance our future operations given the continued weakness in the BC natural gas price related to export capacity constraints. Consequently, our development program in 2019 will be minimal until such time as commodity prices improve to constructive levels. We also expect the following to occur during 2019 or early 2020:

- **Production to return to unrestricted levels:** We continued to restrict our production throughout July 2019 but forecast sufficient natural gas price improvements by this upcoming September or October for our production to return to unrestricted levels of approximately 4,000 boe/d. However, we continue to be hindered by third party outages including at the McMahon Plant that unexpectedly has shut-in all of our production since July 30th. This plant is expected to be operational the week of August 12th.
- **$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 commodity price contracts:** We intend to layer in additional commodity price risk contracts to guarantee the price we will receive on our future production.
- **Borrowing base redetermination discussions with our lender:** While these discussions are currently ongoing, we are evaluating other financing options including the disposition of natural gas assets, the sale/leaseback of midstream assets and other alternative sources of debt.

Quarterly Information from Operations

Summarized information by quarter for the two years ended June 30, 2019, appears below:

	Jun. 30 2019	Mar. 31 2019	Dec. 31 2018	Sept. 30 2018	Jun. 30 2018	Mar. 31 2018	Dec. 31 2017	Sept. 30 2017
Production Volumes								
Natural gas liquids (boe/d)	**279**	455	405	707	680	468	551	405
Natural gas (mcf/d)	**8,457**	15,389	14,641	24,454	22,253	13,806	19,240	14,109
Crude oil (bbl/d)	**10**	9	12	24	23	19	21	19
Average daily production (boe/d)	**1,698**	3,029	2,856	4,807	4,413	2,788	3,779	2,776
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 43.02**	$ 49.96	$ 43.56	$ 63.73	$ 66.65	$ 58.35	$ 51.87	$ 42.07
Average natural gas price ($/mcf)	**$ 1.38**	$ 2.10	$ 2.60	$ 1.54	$ 1.40	$ 2.64	$ 0.99	$ 1.20
Average oil price ($/bbl)	**$ 67.20**	$ 57.89	$ 54.13	$ 71.35	$ 75.11	$ 68.34	$ 76.96	$ 51.49
Operating Netback(1)								
Average commodity pricing ($/boe)	**$ 14.33**	$ 18.34	$ 19.72	$ 17.59	$ 17.75	$ 23.35	$ 13.02	$ 12.61
Royalty (expense) recovery ($/boe)	**$ (0.22)**	$ (0.04)	$ (0.14)	$ -	$ (0.07)	$ (0.17)	$ (0.08)	$ 0.52
Realized (loss) gain on derivative contracts ($/boe)	**$ (0.89)**	$ (1.69)	$ (2.59)	$ (0.17)	$ 0.17	$ (1.18)	$ 3.83	$ 6.54
Net production expenses ($/boe)(1)	**$ (17.26)**	$ (11.28)	$ (14.01)	$ (9.74)	$ (10.17)	$ (14.84)	$ (11.06)	$ (12.32)
Operating netback ($/boe)(1)(2)	**$ (4.04)**	$ 5.33	$ 2.98	$ 7.68	$ 7.68	$ 7.16	$ 5.71	$ 7.35
Wells Drilled								
Exploratory wells (net)	**-**	-	-	-	-	2.00	-	-
Natural gas wells (net)	**-**	-	-	-	-	-	-	-
FINANCIAL ($ thousands, except per share amounts)								
Petroleum & natural gas revenues, net of royalties	**$ 2,178**	$ 4,991	$ 5,146	$ 7,778	$ 7,098	$ 5,815	$ 4,499	$ 3,351
Adjusted funds (outflow) flow (1)	**$ (1,708)**	$ 194	$ (413)	$ 2,285	$ 1,836	$ 471	$ 1,100	$ 647
Per share - basic & diluted ($/share)	**$ (0.01)**	$ -	$ -	$ 0.01	$ 0.01	$ -	$ 0.01	$ -
Cash (outflow) inflow from operating activities	**$ (1,940)**	$ (157)	$ (378)	$ 1,132	$ 1,223	$ (1,722)	$ 2,635	$ (1,352)
Net loss (3)	**$ (22,242)**	$ (2,496)	$ (21,141)	$ (1,944)	$ (2,471)	$ (2,098)	$ (21,160)	$ (3,923)
Per share - basic & diluted ($/share)	**$ (0.10)**	$ (0.01)	$ (0.09)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.10)	$ (0.02)
Development and exploration expenditures	**$ -**	$ -	$ 213	$ -	$ 180	$ 2,497	$ 7,253	$ 14,733
Net debt (surplus)(1)	**$ 5,207**	$ 3,120	$ 1,994	$ 713	$ 2,654	$ 3,961	$ 711	$ (3,616)
Total assets	**$ 77,284**	$ 97,022	$ 101,416	$ 120,572	$ 123,637	$ 127,227	$ 130,571	$ 155,799
Common Shares (thousands)								
Weighted average during period								
Basic and diluted	**223,681**	223,642	223,605	223,605	223,603	223,565	218,517	217,115
Outstanding at period end	**223,682**	223,655	223,605	223,605	223,605	223,565	223,565	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 $18.9 million, $19.6 million and $17.1 million in impairment charges against properties for the three months ended June 30, 2019, 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, other than the second and third quarters of 2018, extended third party restrictions did not allow us to demonstrate our production potential. Production since the third quarter of 2018 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, as we acted to preserve capital given depressed and volatile BC Station 2 pricing, resulting in us reporting lower measures of net debt. Since then, this trend was interrupted by restricted volumes partially precipitated by depressed BC Station 2 pricing, an increase in our abandonment expenditures and realized losses on commodity price contracts.

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 previous 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 year to date, IFRS 16 caused a decrease of $0.2 million in G&A expense before recoveries (see "G&A Expense") whereas it increased DD&A (see "DD&A") by $0.4 million. As a result, our year to date adjusted funds outflow decreased by $0.2 million whereas the net loss increased by the equivalent amount. The effect on the net loss was because during the comparative period the equivalent fixed lease payments of $0.5 million (see "Lease Liabilities") were not entirely expensed, rather a portion were reported as a reduction to the onerous contract provision. The majority of the reported lease liabilities' amount on adoption of IFRS 16 was associated with our previous Calgary office space contract which expired on June 30, 2019.

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 April 1, 2019 and ended June 30, 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 (outflow) 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. Adjusted funds (outflow) flow per share is calculated as adjusted funds (outflow) flow divided by the period’s diluted shares. We believe that adjusted funds (outflow) flow is a key measure to assess our ability to finance capital expenditures and when debt is drawn, to finance debt repayments. Adjusted funds (outflow) flow is not intended to represent cash flow from operating activities, net 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 (outflow) inflow from operating activities as determined in accordance with IFRS as an indicator of our financial performance. Adjustments to cash (outflow) inflow 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 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 either non-cash liabilities, estimates based on management’s assumptions and subject to volatility or where the contractual benefit has yet to be received. Mark-to-market commodity contracts and assets and liabilities held for sale are excluded as they are unrealized estimates subject to a high degree of volatility prior to settlement.

- 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 loss 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: forecasted breaches of a financial covenant in our credit facility over the next 12 months, 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 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 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 Aitken Creek Pipeline provides us optionality upon the future development of a gas plant, that a third party will be tied into this pipeline by early 2020 resulting in an increase in processing & gathering revenues, that we could secure further commodity marketing contracts, that TCPL's North Montney expansion will be completed in 2019, the estimated effects on our operations caused by the rupture of one of the T-South Pipelines and that forecasted natural gas price improvements by this upcoming September or October will result in unrestricted levels of approximately 4,000 boe/d.

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, that our lender may reduce the availability of our $10.0 million credit facility or demand repayment of all outstanding debt and undrawn letters of credit precipitated by a financial covenant breach and that covenant's forecasted breaches over the next 12 months, and, in such event, that no sufficient alternative financing will be completed, that there are material uncertainties that may cast significant doubt with respect to our ability to continue as a going concern, 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.