2018 Management's Discussion and Analysis

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

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. and its wholly owned subsidiaries (collectively, "our", "we" or "us") for the three months and years ended December 31, 2018 and 2017 and should be read in conjunction with our audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2018 and 2017 (the "Financial Statements). This MD&A is based on information available as at March 6, 2019.

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

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. 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"), once filed, can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The Financial Statements have been prepared in accordance with 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.

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 December 31		Year ended December 31	
	2018	2017	**2018**	2017
OPERATIONS				
Production (1)				
Natural gas liquids (boe/d)	**405**	551	**565**	470
Natural gas (mcf/d)	**14,641**	19,240	**18,806**	17,602
Crude oil (bbl/d)	**12**	21	**19**	22
Average daily production (boe/d) (2)	**2,856**	3,779	**3,719**	3,425
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 43.56**	$ 51.87	**$ 59.87**	$ 47.89
Average natural gas price ($/mcf)	**$ 2.60**	$ 0.99	**$ 1.91**	$ 1.95
Average oil price ($/bbl)	**$ 54.13**	$ 76.96	**$ 69.15**	$ 62.27
Operating Netback (3)				
Average commodity pricing ($/boe)	**$ 19.72**	$ 13.02	**$ 19.11**	$ 16.97
Royalty (expense) recovery ($/boe)	**$ (0.14)**	$ (0.08)	**$ (0.08)**	$ 0.05
Realized (loss) gain on commodity price contracts ($/boe)	**$ (2.59)**	$ 3.83	**$ (0.72)**	$ 3.02
Net production expense ($/boe) (3)	**$ (14.01)**	$ (11.06)	**$ (11.63)**	$ (11.57)
Operating netback ($/boe) (2) (3)	**$ 2.98**	$ 5.71	**$ 6.68**	$ 8.47
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	**$ 5,146**	$ 4,499	**$ 25,837**	$ 21,271
Cash (outflow) inflow from operating activities	**$ (378)**	$ 2,635	**$ 255**	$ 6,118
Adjusted funds (outflow) flow (3)	**$ (413)**	$ 1,100	**$ 4,179**	$ 4,978
Per share - basic & diluted ($/share)	**$ -**	$ 0.01	**$ 0.02**	$ 0.02
Net loss	**$ (21,141)**	$ (21,160)	**$ (27,654)**	$ (16,914)
Per share - basic and diluted ($/share)	**$ (0.09)**	$ (0.10)	**$ (0.12)**	$ (0.08)
Capital expenditures	**$ 213**	$ 7,253	**$ 2,890**	$ 39,044
Net debt (3)	**$ 1,994**	$ 711	**$ 1,994**	$ 711
Total assets	**$ 101,416**	$ 130,571	**$ 101,416**	$ 130,571
Common Shares (thousands)				
Weighted average during period - basic & diluted	**223,605**	218,517	**223,594**	217,174
Outstanding at period end	**223,605**	223,565	**223,605**	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.

Operations

Petroleum and Natural Gas Production Volumes

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Natural gas liquids (boe/d)	**405**	551	**565**	470
Natural gas (mcf/d)	**14,641**	19,240	**18,806**	17,602
Crude oil (bbl/d)	**12**	21	**19**	22
Total (boe/d)	**2,856**	3,779	**3,719**	3,425

During the fourth quarter our production decreased by 923 boe/d compared to the same period of 2017. Our production volumes were partially suspended immediately following the October 9, 2018 rupture of one of Enbridge's two natural gas T-South Pipelines ("T-South Pipelines"). The pipeline was repaired and made operational in November 2018. Since being put back into service, Enbridge has operated the T-South Pipelines at reduced pressures, limiting throughput capacity, through the winter season. Because take away volumes were limited from BC, it had an unfavorable effect on the fourth quarter's BC Station 2 benchmark price. As a result, we voluntarily suspended production for the remainder of October and the first half of November except to fulfill our approximate 5,425 GJ/d Chicago City Gate priced contract. In response to continued depressed BC Station 2 benchmark pricing, from mid-November through the remainder of the fourth quarter we temporarily obtained additional pipeline capacity which increased our natural gas production volumes sold at the Chicago City Gate benchmark.

Integrity and maintenance issues on Enbridge's Oak 16" gathering line (the "Oak Pipeline") as followed by the previously discussed capacity constraints on the T-South Pipelines and its effect on BC Station 2 pricing combined to restrict our volumes during the reported year. Despite these restrictions, compared to 2017, the reported year's production volumes increased 294 boe/d as we benefited from our 2016 and 2017 Montney drilling programs at our Birley/Umbach area that resulted in seven (6.27 net) horizontal wells. Specifically, the reported year's restrictions, which began in November 2017 with integrity and maintenance issues on the Oak Pipeline, continued until a temporary pipeline was put in place in early April. A permanent replacement for this temporary pipeline is expected during the first half of 2019. There were further temporary restrictions related to the Oak Pipeline imposed on us through early April and most of June. These issues were all resolved in early July. As previously alluded, during the majority of the fourth quarter we voluntarily suspended approximately one-half of our production in response to depressed BC Station 2 benchmark pricing attributed to lower operating pressures on the T-South Pipelines. Our 2017 production was also effected by a longer than scheduled Enbridge McMahon Plant (the "McMahon Plant") turnaround.

Our fourth quarter production volumes decreased 41% compared to the 4,807 boe/d reported during the third quarter. This decrease was caused by the previously discussed voluntary restrictions in response to depressed BC Station 2 benchmark pricing. Our third quarter production was relatively unaffected by the previously discussed Oak Pipeline integrity and maintenance issues.

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 December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2018**	2017	**2018**	2017
Natural gas liquids sales	**$ 1,621**	$ 2,628	**$ 12,354**	$ 8,208
$/boe	**43.56**	51.87	**59.87**	47.89
Natural gas sales	**$ 3,504**	$ 1,746	**$ 13,103**	$ 12,503
$/mcf	**2.60**	0.99	**1.91**	1.95
Oil sales	**$ 58**	$ 152	**$ 490**	$ 503
$/bbl	**54.13**	76.96	**69.15**	62.27
Petroleum & natural gas revenue	**$ 5,183**	$ 4,526	**$ 25,947**	$ 21,214
$/boe	**19.72**	13.02	**19.11**	16.97

Our petroleum and natural gas revenues for the current reporting periods increased compared to the same periods of 2017 because of higher overall realized pricing due to changes in various commodity benchmarks. More specifically, the reported year's increase was due to both higher production of natural gas and its associated liquids and NGL pricing whereas the fourth quarter's increase was caused by significantly higher natural gas pricing. Although largely offset by production restrictions, as previously discussed, the reported year's higher production volumes resulted from previous years' Montney drilling programs at our Birley/Umbach area. The reported year's higher overall realized price was caused by increases in both various NGL benchmarks and the ratio of natural gas and its associated liquid production contributed from our Birley/Umbach area relative to our total production volumes. This area's production is condensate rich and its natural gas production has a higher heat content compared to the production from our other operations resulting in higher realized pricing. The higher natural gas price during the fourth quarter was caused by an increased ratio of natural gas sold at the Chicago City Gate benchmark. This benchmark is priced at a significant premium relative to the BC Station 2 benchmark. As previously discussed, we obtained additional temporary pipeline capacity priced at the Chicago City Gate benchmark in reaction to depressed BC Station 2 pricing. The increased ratio of natural gas sold at the Chicago City Gate benchmark also supported our realized natural gas price during the reported year.

Benchmark Prices

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Natural gas liquids				
Canadian light sweet (1) ($/bbl)	**$ 42.69**	$ 65.68	**$ 69.32**	$ 61.85
Natural gas				
BC Westcoast Station 2 (2) ($/mcf)	**$ 0.67**	$ 0.60	**$ 1.25**	$ 1.59
Chicago City Gate (3) (US$/mcf)	**$ 3.63**	$ 3.55	**$ 3.06**	$ 3.74

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

NGL Pricing

During the current reporting periods, consistent with the directional change in Canadian light sweet oil and various other liquids and condensate benchmarks, our realized NGL pricing of $43.56/boe and $59.87/boe changed compared to the same periods of 2017. Our NGL price is a blend of prices received for a range of liquids from ethane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however, we benchmark our liquids in reference to Canadian light sweet oil. The ratio of our NGL price relative to Canadian light sweet oil increased to 102% and 86% for the current reporting periods, from 79% and 77% for the same periods of 2017. These ratios increased because we managed our operations during the current reporting periods to maximize liquid recoveries given production restrictions. However, the increases in these ratios were also exaggerated by the precipitous decrease in the Canadian light sweet benchmark.

Our realized NGL price decreased 33% during the fourth quarter compared to the $63.73/boe realized price reported during the third quarter. This decrease corresponds with the lower Canadian light sweet benchmark price caused by volatility in both the national and global oil markets.

Natural Gas Pricing

Our realized natural gas price of $2.60/mcf during the fourth quarter significantly increased compared to the $0.99/mcf for the same quarter of 2017. Inversely, our natural gas price of $1.91/mcf during the reported year decreased compared to $1.95/mcf for 2017. These realized natural gas pricing changes are due to changes in benchmark pricing and in the weighted average ratio of natural gas production sold at each benchmark price relative to total natural gas production. Generally, because we sell the majority of our natural gas production at the BC Station 2 benchmark, the change in our reported year's realized natural gas prices, compared to 2017, correspond to the change in this benchmark. However, we also sell a portion of our natural gas production at the Chicago City Gate benchmark where we have firm pipeline capacity of approximately 5,425 GJ/d through to October 31, 2020. In addition, effective November 1, 2018, we obtained additional pipeline capacity through to March 31, 2019 of approximately 4,250 GJ/d, albeit with a larger associated transportation toll, also sold at the Chicago City Gate benchmark. Despite this benchmark decreasing during the reported year, in comparison to 2017, selling our natural gas at Chicago City Gate benchmark pricing results in us realizing a significant premium compared to BC Station 2 pricing. Specifically, during the current reporting periods we sold 72% and 34% of our natural gas production at the Chicago City Gate benchmark compared to 27% and 25% during the same periods of 2017. The significant increase in the fourth quarter ratio, and to a lesser extent during the reported year, resulted from us selling more of our natural gas production at Chicago City Gate benchmark pricing as we obtained additional pipeline capacity sold at this benchmark combined with the shut-in of production due to third party constraints or in reaction to depressed BC Station 2 benchmark pricing. The increase in the reported year's ratio was also because of the absence of the comparative year's June restrictions which prevented us from delivering volumes at Chicago pricing.

Despite a 48% decrease in the BC Station 2 benchmark, our realized natural gas price increased 69% during the fourth quarter compared to $1.54/mcf reported during the third quarter. This increase was due to both higher Chicago City Gate benchmark pricing and the ratio of our natural gas production sold at this benchmark price relative to our total natural gas sales.

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Royalty expense (recovery)	**$ 37**	$ 27	**$ 110**	$ (57)
Per sales ($/boe)	**$ 0.14**	$ 0.08	**$ 0.08**	$ (0.05)
Percent of revenues (%)	**1**	1	**-**	-

We are reporting negligible royalties for all reported periods. During 2017, we were granted royalty credits as part of BC's Infrastructure Royalty Credit Program (the "Infrastructure Program"). This program provides credits on our Birley/Umbach development only after sufficient crown royalties have been generated by specific wells. We recognized $0.2 million and $0.9 million of these credits through a decrease to our royalties during the current reporting periods. These are the same decreases we recognized during the comparative periods of 2017. 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. The 2017 recovery was caused by adjustments to our previous Alberta Gas Cost Allowance estimates. Royalties in Alberta are no longer significant to our operations. Overriding and freehold royalties will continue to be payable.

Financial Commodity Price Contracts

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

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

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

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Realized loss (gain) on commodity price contracts	**$ 680**	$ (1,332)	**$ 982**	$ (3,770)
Unrealized loss (gain) on commodity price contracts	**(703)**	1,153	**235**	(154)
Loss (gain) on commodity price contracts	**$ (23)**	$ (179)	**$ 1,217**	$ (3,924)
Realized (loss) gain on commodity price contracts ($/boe)	**$ (2.59)**	$ 3.83	**$ (0.72)**	$ 3.02

During the current reporting periods, we realized losses on our Chicago City Gate price indexed contract where our contracted price of US$2.68/mmbtu was lower than the pricing for this benchmark. If we had included these losses in our natural gas revenues, we would have reported an adjusted natural gas sales price for the current reporting periods of $2.10/mcf and $1.77/mcf compared to our reported price of $2.60/mcf and $1.91/mcf.

Outstanding Commodity Price Contracts

As at December 31, 2018, our outstanding commodity price contracts had the following terms:

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

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

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

Subsequent to December 31, 2018, we entered into the following commodity price contracts:

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 collar		
October 1, 2019 to December 31, 2019	3,000 mmbtu/d	NYMEX (3) US$2.25/mmbtu to US$3.68/mmbtu
Natural gas differential swap		
October 1, 2019 to December 31, 2019	3,000 mmbtu/d	Price at Chicago = NYMEX (3) less US$0.125/mmbtu

(3) NYMEX is the abbreviation for the New York Mercantile Exchange.

The combination of the NYMEX natural gas collars and differential swaps provide us a minimum and maximum price on notional volumes sold at Chicago City Gate Monthly pricing during the fourth quarter of 2019.

Mark-to-Market

At December 31, 2018, our crude oil swaps were in a $0.4 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 $0.6 million liability position because the forward Chicago City Gate and NYMEX benchmark pricing had increased relative to our contracted prices. The combined fair value net liability resulted in an unrealized loss of $0.2 million for the reported year.

Net Production Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Production & operating	**$ 3,959**	$ 4,157	**$ 16,845**	$ 15,476
Less:				
Processing & gathering revenues	**(276)**	(312)	**(1,050)**	(1,006)
Net production expense [(1)]	**$ 3,683**	$ 3,845	**$ 15,795**	$ 14,470
Net production expense ($/boe) [(1)]	**$ 14.01**	$ 11.06	**$ 11.63**	$ 11.57
Production expense ($/boe)	**$ 15.06**	$ 11.96	**$ 12.41**	$ 12.38

(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 reported year's production expense, on a boe basis, was relatively unchanged compared to 2017. For the reported year, production & operating costs were affected by production restrictions caused by the third party constraints or our reaction to depressed BC Station 2 benchmark pricing. In addition, to prevent our production from freezing during the first quarter, we also incurred higher labour and steamer costs to flow restricted volumes through the extremely cold winter weather. These higher costs could have been avoided had our production been unimpeded. Specifically, during the reported year our Birley/Umbach area averaged a production expense of $9/boe as compared to the overall reported production expense of $12.41/boe. For the same period of 2017, our operating costs were effected by a longer than expected McMahon Plant turnaround. All of these restrictions had the effect of increasing the contribution, on a boe basis, from fixed operating costs relative to total operating costs.

On a boe basis, production & operating expenses for the fourth quarter increased compared to the same period of 2017. This increase was due to lower reported volumes caused by production restrictions resulting from the rupture of one of the T-South Pipelines and associated depressed BC Station 2 benchmark pricing. The fourth quarter's comparative period was also affected by the previously discussed Oak Pipeline integrity and maintenance issues.

We started reporting new toll revenue in June 2017 from our 12" Aitken Creek Pipeline which is directly connected to the Alliance Pipeline. This resulted in higher processing and gathering revenues during the reported year compared to 2017 but as largely offset by lower compression and gathering income at our Martin Creek property caused by lower third party throughput. 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.

Operating Netback

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

	Three months ended December 31		Year ended December 31	
Per sales ($/boe)	**2018**	2017	**2018**	2017
Average commodity pricing	**$ 19.72**	$ 13.02	**$ 19.11**	$ 16.97
Royalty (expense) recovery	**(0.14)**	(0.08)	**(0.08)**	0.05
Realized (loss) gain on commodity price contracts	**(2.59)**	3.83	**(0.72)**	3.02
Net production expense [1]	**(14.01)**	(11.06)	**(11.63)**	(11.57)
Operating netback [1]	**$ 2.98**	$ 5.71	**$ 6.68**	$ 8.47

(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 2017. Although the current reporting periods include higher average commodity pricing partially attributed to a shift in the ratio towards natural gas sold at the premium priced Chicago City Gate benchmark relative to total natural gas sales, this shift resulted from production restrictions. The effect of these restrictions was a higher per boe net production expense. For the current reporting periods and on a boe basis, compared to the same periods of 2017, despite production restrictions if we isolate the average commodity price less the net production expense we achieved higher operating netbacks. However, these higher operating netbacks were more than offset by the combination of realized losses on a commodity price contract during the current reporting periods and the absence of the comparative periods realized gains of $3.83/boe and $3.02/boe.

Take or Pay Contract and Other Losses (Income)

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Take or pay contract revenue	**$ (801)**	$ (1,049)	**$ (3,821)**	$ (2,974)
Take or pay contract expense	**$ 945**	$ 1,198	**$ 4,389**	$ 3,500
Other losses (income)	**$ 5**	$ (144)	**$ (22)**	$ 105

During the reported periods, we incurred a net fee for a take or pay processing agreement which we partially mitigated by purchasing production from a third party. The net fee during the current reporting periods compares to the same periods of 2017. We have partially mitigated our continued exposure to this fee at least through to the first quarter of 2019. Beyond then, we are in active discussions with various third parties. 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 December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
G&A expense before recoveries	**$ 1,375**	$ 1,661	**$ 5,862**	$ 8,301
Recoveries	**(356)**	(737)	**(1,748)**	(3,057)
G&A expense	**$ 1,019**	$ 924	**$ 4,114**	$ 5,244
Per sales ($/boe)	**$ 3.88**	$ 2.66	**$ 3.03**	$ 4.19

For the current reporting periods and as implemented throughout 2017, we realized lower G&A expenses before recoveries including lower staffing costs due to reductions in headcount, a lower number of directors, reduced employee benefits and reduced information system costs. Further, for the reported year we reduced our headcount by 40%, suspended an employee benefit program and implemented a reduced work week from May to September 2018. We estimate the headcount reduction and suspension of the employee benefit program will result in additional G&A cost savings of approximately $1.4 million per year. During the fourth quarter and because of these 2018 implemented cost reductions, we estimate we realized G&A costs savings of $0.4 million.

As a result of reporting an onerous contract non-cash charge during 2017, an additional $0.4 million of rent expenditures during the reported year that was previously reported as G&A expense instead reduced our onerous contract provision (see “Onerous Contract and Indemnifications”). If current rental market conditions remain the same or similar, we anticipate significantly lower rent costs commencing in mid-2019 upon our lease expiration.

Partially offsetting the above G&A expense before recovery decreases were lower G&A recoveries. With lower compensation costs combined with reduced capital expenditures, our capitalized G&A, capital and other associated G&A recoveries decreased by $0.4 million and $1.3 million during the current reporting periods compared to the same periods of 2017. For the fourth quarter, the lower G&A recoveries more than offset our cost reduction efforts.

G&A on a boe basis also decreased during the reported year compared to 2017 as a result of lower overall G&A expense described above combined with modestly higher production. Inversely, G&A on a boe basis for the fourth quarter increased compared to the same quarter of 2017 due to the combination of both lower G&A recoveries and production.

Severance Costs

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Severance costs	**$ -**	$ 34	**$ 834**	$ 705

Severance costs incurred during the reported year and its comparable period related to staffing reductions resulting from a continuing assessment of our staffing requirements. As previously discussed, during the reported year we reduced our headcount by 40%.

Exploration and Evaluation Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Exploration & evaluation expense	**$ 60**	$ 11	**$ 171**	$ 272

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

Impairment of Development & Production Assets

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Impairment of development & production assets	**$ 19,600**	$ 17,100	**$ 19,600**	$ 17,100

Despite a modest increase in our proved and probable reserve volumes, we identified evidence indicating impairment in the December 31, 2018 carrying value of our development and production assets. This evidence was a significant sustained reduction in forward BC Station 2 natural gas pricing combined with reduced forward pricing over the next three years in the Western Canadian Select benchmark. As a result, on the December 31, 2018 carrying value, we tested for impairment on our one remaining Peace River Arch CGU. For the reported year, this test revealed impairment of $19.6 million as compared to 2017 when we recognized impairment of $17.1 million.

The CGU's recoverable value of $82.9 million was estimated using a value-in-use calculation based on a December 31, 2018 independently prepared reserve report. 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)	
As at December 31,	**2018 (3)**	**2017 (4)**	**2018 (3)**	**2017 (4)**
2019	$ 51.55	$ 57.00	$ 1.80	$ 2.28
2020	$ 59.58	$ 61.40	$ 2.20	$ 2.69
2021	$ 65.89	$ 66.00	$ 2.65	$ 3.14
2022	$ 68.61	$ 67.90	$ 2.95	$ 3.34
2023	$ 70.53	$ 69.20	$ 3.10	$ 3.41
Thereafter, increasing per year	2%	2%	2%	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 January 1, 2019.
(4) Source: McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2018.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Depletion, depreciation & amortization	**$ 2,367**	$ 3,148	**$ 11,654**	$ 11,622
Depletion per sales ($/boe)	**$ 7.51**	$ 7.66	**$ 7.36**	$ 7.79

DD&A expense decreased on a boe basis during the current reporting periods compared to the same periods of 2017. These lower depletion rates were due to the comparative period's recognition of a $17.1 million impairment charge against the carrying value of our development and production assets. The current reporting periods' decreased rates were also caused by a modest increase in the December 31, 2018 measure of our proved plus probable reserves. Similarly, we previously reported an increase in the December 31, 2017 measure of our proved plus probable reserves which also contributed to the reported year's lower depletion rate. During the fourth quarter, both a lower rate and production volumes resulted in an overall decrease in DD&A compared to the same quarter of 2017. During the reported year, the effect from a lower rate was offset by a modest increase in production volumes resulting in DD&A being relatively unchanged in comparison to 2017.

Deferred Customer Obligation Amortization

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Deferred customer obligation amortization	**$ (194)**	$ (220)	**$ (777)**	$ (583)

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

Gain on Dispositions of Properties

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Gain on dispositions of properties	**$ (721)**	$ -	**$ (721)**	$ (10,926)

During the current reporting periods, we disposed of mineral rights with associated undeveloped lands, shut-in and suspended wells located in Rigel, British Columbia and Gordondale, Alberta to third parties in consideration for them assuming the decommissioning obligations. There were no reserves associated with these mineral rights. The $0.2 million net carrying amount of the undeveloped lands less $0.9 million of associated decommissioning obligations resulted in a gain on the transfer of properties of $0.7 million.

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

Share-Based Compensation

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Share-based compensation	**$ 149**	$ 215	**$ 508**	$ 906

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

Amortization of Flow-Through Common Shares Premium

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Amortization of flow-through common shares premium	**$ -**	$ -	**$ (323)**	$ -

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

Onerous Contract and Indemnifications

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Onerous contract and indemnifications	**$ -**	$ 276	**$ -**	$ 1,837

During 2017, we recognized a $1.8 million non-cash charge resulting from both the onerous portion of our Calgary head office lease contract and an increase to a provision for certain indemnifications we had previously provided to the buyer of our former Tunisian operations (see "Provisions").

Bad Debt Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Bad debt expense	**$ -**	$ 300	**$ -**	$ 300

In an effort to manage our credit risk we continuously monitor and assess the collectability of our purchaser and jointly owned asset partners' receivables in addition to our other receivable positions. For the comparative year we identified $0.3 million of receivables, due from partners where we held jointly owned assets that we have since conveyed, that were deemed uncollectible.

Financing Expenses

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Interest & financing expense (income)	**$ 28**	$ 23	**$ 180**	$ (161)
Accretion of provisions	**170**	177	**693**	692
Financing expenses	**$ 198**	$ 200	**$ 873**	$ 531

During the reported year, we incurred interest & financing expenses compared to income in the same period of 2017. The effective interest rates on drawn debt were 4.9% and 4.6% during the current reporting periods. This higher effective interest rate during the fourth quarter was due to an increase in the lender's prime rate. We expect a decrease in the effective interest rate to 4.5% during the first quarter of 2019 assuming the lender's prime rate remains unchanged. This expected decrease results from lower net debt relative to cash flows (defined under the section "Credit Facility"). The comparative year's interest income resulted from cash-on-hand which subsequently financed a portion of our development, exploration, provision and severance expenditures.

The accretion charges during the reported periods are comparable to one another because the effect from the current reporting periods' lower applied decommissioning obligations' risk-free discount rate was offset by a higher provision initially reported during the fourth quarter of 2017 caused by the Birley/Umbach facility expansion from 25 mmcf/d to 50 mmcf/d.

Income Tax

We have not reported deferred tax assets because it is not probable that we can utilize our tax pools against future taxable profit. We estimate we had the following tax pools as 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 December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Weighted average shares outstanding - basic & diluted (thousands)	**223,605**	218,517	**223,594**	217,174
Net & comprehensive loss	**$ (21,141)**	$ (21,160)	**$ (27,654)**	$ (16,914)
Net loss per share - basic & diluted ($/share)	**$ (0.09)**	$ (0.10)	**$ (0.12)**	$ (0.08)

For the fourth quarter and same period of 2017, we recognized comparable net losses whereas for the reported year our net loss increased to $27.7M compared to $16.9 million during 2017. Despite higher petroleum & natural gas revenues resulting from higher average commodity pricing, the reported year's increased net loss resulted from realized losses on commodity price contracts, as compared to gains during 2017, production restrictions, a higher impairment charge against development and production assets and the absence of a $10.9 million gain on the disposition of properties as reported during the comparative year.

Capital Resources, Capital Expenditures and Liquidity

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

During the reported year, despite having a highly unleveraged balance sheet, upon its scheduled May 2018 reassessment our lender reduced its availability of the demand credit facility from $18.0 million to $10.0 million. Since then we have observed lower forward commodity pricing. As a result we anticipate that during the next scheduled May 2019 reassessment, our lender may impose a further reduction in the availability of the demand credit facility. During the fourth quarter, our debt increased to $2.4 million as attributed to lower petroleum and natural gas revenues caused by restricted production stemming from short-term third party infrastructure 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 current reporting periods, 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 as well as complete the Birley facility expansion to 50 mmcf/d puts us in an excellent position to accelerate activity when commodity prices recover.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2018**	2017	**2018**	2017
Cash (outflow) inflow from operating activities	**$ (378)**	$ 2,635	**$ 255**	$ 6,118
Add back:				
Change in operating non-cash working capital	**(690)**	(2,287)	**1,311**	(3,284)
Provision expenditures	**595**	707	**1,608**	1,167
Exploration & evaluation expenses	**60**	11	**171**	272
Severance costs	**-**	34	**834**	705
Adjusted funds (outflow) flow (1)	**$ (413)**	$ 1,100	**$ 4,179**	$ 4,978
Per share - basic & diluted	**$ -**	$ 0.01	**$ 0.02**	$ 0.02

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

Despite higher overall realized pricing, adjusted funds flow decreased for the current reporting periods compared to the same periods of 2017 as a result of production restrictions and realized losses on commodity price contracts. These losses compare to realized gains on commodity price contracts of $1.3 million and $3.8 million during the same periods of 2017. The reported year's adjusted funds flow also benefited from a $1.1 million decrease in overall G&A expense compared to the same period of 2017.

For the same reasons as just explained for the decreases in adjusted funds flows, cash flows from operating activities also decreased for the current reporting periods compared to the same periods of 2017. For the reported year this decrease was also caused by higher provision expenditures on decommissioning obligations and the onerous portion of our head office rent costs. The reported year's decrease was further caused by financing a build in our non-cash working capital resulting from securing seasonal firm pipeline capacity most of which was returned to us in January 2019 (see "Commitments and Guarantees").

Net Debt

($ thousands)	December 31 2018	December 31 2017
Debt	$ (2,361)	$ -
Cash	-	4,341
Accounts receivable	3,386	3,490
Prepaids & deposits	2,528	1,373
Accounts payable & accrued liabilities	(5,547)	(9,915)
Net debt (1)	$ 1,994	$ 711

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

We had net debt of $2.0 million and $0.7 million at December 31, 2018 and 2017, respectively. Net debt increased between these reported dates because the reported year's adjusted funds flow of $4.2 million was more than offset by development, provision, severance and exploration & evaluation expenditures. We normally manage expenditures not to exceed our annual adjusted funds flow. However, during 2017 we raised proceeds from the issuance of flow-through shares, where these proceeds decreased our net debt as at December 31, 2017, with a commitment to spend $2.0 million of qualifying exploration expenditures as incurred during the reported year. In the absence of these flow-through share proceeds and the resulting subsequent spend, during 2018 we did manage our expenditures within our annual adjusted funds flow.

Credit Facility

As a result of the scheduled May 2018 semi-annual review, we amended our demand credit facility agreement with a Canadian chartered bank resulting in a revised availability of $10.0 million as at December 31, 2018 (the "Demand Credit Facility"). At December 31, 2017, the facility's availability was $18.0 million. The Demand Credit Facility's next scheduled semi-annual review is May 2019. As at December 31, 2018, we had debt borrowings of $2.4 million and outstanding letters of credit of $0.9 million, as secured by our lender, which reduced the available Demand Credit Facility credit to $6.7 million (at December 31, 2017 – drawings of $nil, outstanding letters of credit of $0.8 million and available credit of $17.2 million).

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

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

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

As at the end of any 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 the date of this MD&A, we were in compliance with the foregoing financial covenants and other requirements under the Demand Credit Facility.

Capital Expenditures

Our capital expenditures during the reported periods were as follows:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Land & lease	**$ 88**	$ -	**$ 262**	$ 182
Drilling & completions	**125**	82	**2,225**	22,712
Facilities & equipment	**-**	7,027	**253**	15,420
Field expenditures	**213**	7,109	**2,740**	38,314
Capitalized G&A	**-**	144	**150**	730
Total	**$ 213**	$ 7,253	**$ 2,890**	$ 39,044
Proceeds from dispositions	**$ -**	$ -	**$ -**	$ 17,838

During the reported year, we drilled and completed two (2.0 net) vertical exploratory wells in the Birley/Umbach area for $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 but will now be fully abandoned in the first half of 2019 to satisfy flow-through financing obligations. These 21 gross sections of Montney mineral rights include four sections we secured during the reported year that further reinforce our land position adjacent to the two (2.0 net) aforementioned exploratory Birley/Umbach vertical wells.

Disposition of Properties

During the current reporting periods, we disposed of mineral rights located in Rigel, British Columbia and Gordondale, Alberta to third parties in consideration for them assuming the associated decommissioning obligations of suspended and shut-in wells and associated infrastructure. There were no reserves associated with these mineral rights.

During the comparative year, we completed the sale of certain properties located at Knopcik/Pipestone and East Gold Creek areas of northwestern Alberta for combined net proceeds of $17.8 million after customary adjustments. These properties were mostly comprised of undeveloped lands but included land prospective for Montney oil and liquids-rich natural gas with estimated production of 100 boe/d (65% natural gas).

Provisions

Decommissioning Obligations

At December 31, 2018, the net present value of our decommissioning obligations was $32.4 million which was higher than $31.1 million at December 31, 2017. During the reported year, an increase of $1.3 million in decommissioning obligations resulted from additions caused by exploration activities, a change in estimate caused by a decrease in the long-term risk-free interest rate and accretion of $0.7 million which reflects the increase in the obligation associated with the passage of time as partially offset by expenditures and property transfers. We estimate this net present value based on a total future undiscounted and uninflated liability of $33.3 million (December 31, 2017 - $32.7 million).

As at 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 (December 31, 2017 – 2.0% and 2.2%, respectively).

Onerous Contract and Indemnifications

During the comparative year, we recognized a provision caused by the onerous portion of our Calgary head office lease contract. This provision represented the present value of the minimum future lease payments we are obligated to make under the estimated onerous portion of the non-cancellable lease contract less estimated recoveries. At December 31, 2018, the amount of these estimated future expenditures to settle this provision was $0.4 million (December 31, 2017 - $1.2 million). These estimated future expenditures will be incurred through to the Calgary head office lease expiry in June 2019 and were discounted using a risk-free discount rate of 2%.

We are also involved in litigation and claims arising from indemnifications provided to the buyer of our former Tunisian operations in 2014. At December 31, 2018, an estimate of probable future disbursements for these indemnifications, including professional costs, totaled $0.9 million (December 31, 2017 - $1.0 million).

Share Capital

Authorized

- Unlimited number of common shares
- Unlimited number of first preferred shares

Outstanding

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

	December 31 2018	December 31 2017
Common shares outstanding	**223,604,601**	223,564,601
Share options	**13,177,200**	10,276,884
Restricted awards	**127,300**	200,370
Weighted average common shares - basic and diluted	**223,594,409**	217,173,649

As at March 5, 2019, we had 223,654,501 common shares, 17,737,200 share options and 77,400 restricted awards outstanding.

Flow-through Common Share Issuance

On December 11, 2017, we completed the private placement of 6,450,000 common shares on a flow-through basis at a price of $0.31 per flow-through common share for total gross proceeds of $2.0 million. The flow-through common share issuance costs were $0.1 million resulting in net proceeds of $1.9 million. A premium of $0.3 million received on the flow-through common shares was initially recognized as a liability on the consolidated statements of financial position as determined from the difference between the total gross proceeds and the estimated fair value of the equivalent number of our common shares immediately preceding the date of the flow-through common share announcement. During the reported year, we incurred the $2.0 million of qualifying Canadian exploration expenditures on the drilling of the two Birley/Umbach exploratory vertical wells. As a result, we amortized the flow-through common share premium.

Commitments and Guarantees

At December 31, 2018, we had contractual commitments that require the following minimum future payments without giving effect to any offsetting third party agreements which, are anticipated to reduce some of these amounts:

					Year ended December 31
($ thousands)	**2019**	**2020**	**2010**	**Thereafter**	**Total**
Leases	$ 815	$ 8	$ -	$ -	$ 823
Operating and transportation contracts	2,276	888	212		$ 3,376
	$ 3,091	**$ 896**	**$ 212**	**$ -**	**$ 4,199**

Lease commitments include our head office in Calgary, Alberta. This office lease commitment excludes the undiscounted portion considered onerous (see “Onerous Contract and Indemnifications”). Operating and transportation contracts relate to contractual payments if we do not benefit from the operating services or pipeline transportation.

We have also guaranteed indemnifications provided by our wholly owned subsidiary to the buyer of our former Tunisian operations (see “Onerous Contract and Indemnifications” and “Risk Factors”).

At December 31, 2018, 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 (December 31, 2017 - $0.8 million) and through a payment of $1.2 million as included in prepaids and deposits. Subsequent to December 31, 2018, $1.0 million of this payment was refunded to us.

In a previously reported year, we had guaranteed a total of $1.3 million in outstanding letters of credit through depositing an equivalent amount in cash with our lender. During the comparative year, the lender released its restrictions to this cash.

Off Balance Sheet Arrangements

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

Related Party Transactions

We determined that our key management personnel consist of our officers and directors. In addition to the salaries and directors fees paid to the officers and directors, respectively, the officers and directors participate in our long-term share incentive plans, which include a share option plan and a restricted and performance award incentive plan. The officers’ salaries, directors’ fees and other benefits, as mostly included in G&A expense and transaction, distribution and severance costs for the reported and comparable years, totaled $1.7 million and $2.2 million, respectively. Long-term incentive benefits for our officers and directors, as included in share-based compensation for the reported and comparable years, totaled $0.5 million and $0.6 million, respectively.

Alberta Investment Management Corporation ("AIMCo"), as investment manager to Her Majesty the Queen in Right of the Province of Alberta ("HMQ"), maintains investment control and direction over approximately 36% of our outstanding common shares for the benefit of HMQ. Pursuant to a management and administration services agreement (the "Services Agreement") dated June 29, 2010, we were engaged to manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership (“WOGH”). WOGH was formed to hold working interests in certain of our assets which are held by nominees of AIMCo on behalf of HMQ. As we manage, administer and maintain the properties and the books, accounts and records of WOGH, we are reimbursed for such services. In accordance with the Services Agreement, we reported a recovery from WOGH, as mostly reported against our G&A expense, of $0.9 million and $1.1 million for the reported and comparable years. The recovery for the reported and comparative years was generally determined from WOGH’s pro rata share as estimated at 12 percent and 14 percent, respectively, of its and our combined production volumes. At December 31, 2018 and 2017, $0.1 million of this G&A recovery was included in accounts receivable.

First Quarter of 2019 Production Update

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 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 and since then have averaged 4,100 boe/d.

Outlook

We are committed to improving our cost structure and will see our office related expenditures decrease in 2019 primarily through the conclusion of our current office lease and lease of new space at current market rates. Additionally, we continue to lever our existing assets and have 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 late 2019 or early 2020, and will continue for a minimum period of two years. Minimum gathering charges will total approximately $1.6 million annually.

As Western Canadian natural gas price weakness continues related to export capacity constraints, including T-South restrictions, 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.

Selected Annual Information

Summarized information for the reported year and the two preceding years appears below:

Year ended December 31		2018		2017		2016
($ thousands, except per share amounts)						
Petroleum & natural gas revenue, net of royalties	**$**	**25,837**	$	21,271	$	36,943
Net loss (1)	**$**	**(27,654)**	$	(16,914)	$	(54,773)
Per share - basic & diluted ($/share)	**$**	**(0.12)**	$	(0.08)	$	(0.25)
Total assets	**$**	**101,416**	$	130,571	$	139,975
Long-term liabilities (2)	**$**	**33,794**	$	33,377	$	27,767

(1) Includes $19.6 million, $17.1 million and $41.1 million of net impairment charges for the years ended December 31, 2018, 2017 and 2016, respectively.
(2) Includes loans and borrowings, provisions and other long-term liabilities.

Factors That Have Caused Variations over the Years

Petroleum & natural gas revenues, net of royalties decreased from 2016 to 2017 but then increased from 2017 to the reported year. In comparison to 2016, the combined effect of the absence of volumes from conveyed and disposed properties, third party restrictions on our production, a weighted average shift to natural gas and lower natural gas pricing resulted in a decrease in our 2017 petroleum & natural gas revenues, net of royalties. The increase during the reported year, compared to 2017, was due to higher liquid pricing and a modest increase in volumes resulting from our 2016 and 2017 Montney drilling programs at our Birley/Umbach area which resulted in seven (6.27 net) horizontal wells. As previously explained, the reported year's volumes were negatively affected by production restrictions resulting from a combination of the Oak Pipeline maintenance and integrity issue, the rupture of one of the T-South Pipelines resulting in both pipelines subsequently operated at reduced pressures and the associated effect on depressing the BC Station 2 benchmark.

The net losses for each of the above successive years largely resulted from impairment charges caused by sustained decreases in forward Station 2 benchmark pricing. These impairment charges combined with DD&A and property transfers or dispositions contributed to each consecutive year's decrease in total assets.

During each of the above successive years, we increased our decommissioning obligations' estimate as caused by lower long-term risk free discount rates and either exploration or development activities. During the reported year, compared to 2017, the decommissioning obligation increase was partially offset by the amortization of both a deferred customer obligation and a flow-through common shares premium.

Please refer to "Operations" and other sections of this MD&A for detailed discussions on variations between the reported year and its comparative period and to our previous annual management's discussion and analysis for changes between the prior years.

Quarterly Information from Operations

Summarized information by quarter for the two years ended December 31, 2018, appears below:

	Dec. 31 2018	Sept. 30 2018	Jun. 30 2018	Mar. 31 2018	Dec. 31 2017	Sept. 30 2017	Jun. 30 2017	Mar. 31 2017
Production Volumes								
Natural gas liquids (boe/d)	**405**	707	680	468	551	405	441	482
Natural gas (mcf/d)	**14,641**	24,454	22,253	13,806	19,240	14,109	19,065	18,022
Crude oil (bbl/d)	**12**	24	23	19	21	19	19	29
Average daily production (boe/d)	**2,856**	4,807	4,413	2,788	3,779	2,776	3,638	3,514
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 43.56**	$ 63.73	$ 66.65	$ 58.35	$ 51.87	$ 42.07	$ 44.48	$ 51.39
Average natural gas price ($/mcf)	**$ 2.60**	$ 1.54	$ 1.40	$ 2.64	$ 0.99	$ 1.20	$ 2.77	$ 2.71
Average oil price ($/bbl)	**$ 54.13**	$ 71.35	$ 75.11	$ 68.34	$ 76.96	$ 51.49	$ 59.55	$ 60.32
Operating Netback[1]								
Average commodity pricing ($/boe)	**$ 19.72**	$ 17.59	$ 17.75	$ 23.35	$ 13.02	$ 12.61	$ 20.22	$ 21.42
Royalty (expense) recovery ($/boe)	**$ (0.14)**	$ -	$ (0.07)	$ (0.17)	$ (0.08)	$ 0.52	$ (0.33)	$ 0.20
Realized (loss) gain on derivative contracts ($/boe)	**$ (2.59)**	$ (0.17)	$ 0.17	$ (1.18)	$ 3.83	$ 6.54	$ 1.01	$ 1.38
Net production expenses ($/boe)[1]	**$ (14.01)**	$ (9.74)	$ (10.17)	$ (14.84)	$ (11.06)	$ (12.32)	$ (11.82)	$ (11.27)
Operating netback ($/boe)[1][2]	**$ 2.98**	$ 7.68	$ 7.68	$ 7.16	$ 5.71	$ 7.35	$ 9.08	$ 11.73
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	**$ 5,146**	$ 7,778	$ 7,098	$ 5,815	$ 4,499	$ 3,351	$ 6,583	$ 6,838
Adjusted funds (outflow) flow [1]	**$ (413)**	$ 2,285	$ 1,836	$ 471	$ 1,100	$ 647	$ 1,195	$ 2,036
Per share - basic & diluted ($/share)	**$ -**	$ 0.01	$ 0.01	$ -	$ 0.01	$ -	$ 0.01	$ 0.01
Cash (outflow) inflow from operating activities	**$ (378)**	$ 1,132	$ 1,223	$ (1,722)	$ 2,635	$ (1,352)	$ 6,280	$ (1,445)
Net (loss) income[3]	**$ (21,141)**	$ (1,944)	$ (2,471)	$ (2,098)	$ (21,160)	$ (3,923)	$ (2,253)	$ 10,422
Per share - basic & diluted ($/share)	**$ (0.09)**	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.10)	$ (0.02)	$ (0.01)	$ 0.05
Capital expenditures	**$ 213**	$ -	$ 180	$ 2,497	$ 7,253	$ 14,733	$ 8,235	$ 8,823
Net (debt) surplus [1]	**$ (1,994)**	$ (713)	$ (2,654)	$ (3,961)	$ (711)	$ 3,616	$ 18,294	$ 25,622
Total assets	**$ 101,416**	$ 120,572	$ 123,637	$ 127,227	$ 130,571	$ 155,799	$ 144,891	$ 148,665
Common Shares (thousands)								
Weighted average during period - basic	**223,605**	223,605	223,603	223,565	218,517	217,115	216,598	216,443
Weighted average during period - diluted	**223,605**	223,605	223,603	223,565	218,517	217,115	216,598	216,900
Outstanding at period end	**223,605**	223,605	223,605	223,565	223,565	217,115	217,115	216,443

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.
(2) May not be additive due to rounding.
(3) Includes $19.6 million and $17.1 million in impairment charges against properties for the three months ended December 31, 2018 and 2017, respectively, and a $10.9 million gain on disposition of properties for the three months ended March 31, 2017.

Factors That Have Caused Variations over the Quarters

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

Beginning in the first quarter of 2017, our operating and financial results reflect the completion of our transition to a Montney play focused company. Since then, production trended with our Birley/Umbach property including this area's 2016 and 2017 development programs which added seven (6.27 net) horizontal wells, of which five (4.27 net) came on-stream throughout 2017 with the remaining two (2.00 net) coming on-stream during the first quarter. However, during the second half of 2017 and first half of 2018, extended third party restrictions did not allow us to demonstrate our production potential. Although our third quarter production volumes were relatively unaffected by third party constraints, during the fourth quarter further restrictions caused by a rupture on one of the T-South Pipelines affected this period's production volumes. 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 towards BC Station 2 and away from Chicago City Gate benchmark pricing or vice versa. During 2017, our net surplus has generally trended down as our capital expenditures incurred on development and exploration of our Birley/Umbach area exceeded our adjusted funds flow ultimately resulting in us reporting net debt. Since the first quarter through to the third quarter, our adjusted funds flow has exceeded our capital expenditures resulting in us reporting lower measures of net debt. During the fourth quarter 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.

Comparison of Guidance to Actual Results

The following table provides a comparison of our 2018 guidance as announced on August 9, 2018 to our actual operating and financial results:

($ millions, except boe/d)	2018 Guidance	2018 Actuals
Average production (boe/d)	4,000	3,719
Exit production (boe/d)	4,100	3,500
Capital expenditures	$ 2.8	$ 2.9
Abandonment and reclamation expenditures	$ 0.7	$ 0.7
Exit net surplus (debt) (1)	$ 0.5	$ (2.0)

(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.

In our third quarter MD&A, we advised that the above guidance was not going to be met as our production and net debt was negatively impacted by the October 2018 rupture of one of the T-South Pipelines. Although the third party's T-South Pipelines were shortly put back in-service, they were operated at reduced pressures which resulted in depressed winter BC Station 2 pricing. We reacted through voluntarily shutting-in our November and December production other than to meet our Chicago City Gate priced commitments.

Risk Factors

Investors should carefully consider the risk factors set out in our AIF, once filed, 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". The following are the more significant risk factors as copied from the AIF:

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "Risk Factors – Insurance". In either event, the Corporation could incur significant costs.

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and gas industry may affect the value of the Corporation's reserves, restrict its cash flow and its ability to access capital to fund the development of it properties.

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("OPEC"), slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, isolationist trade policies, increased U.S. shale production, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. See "Risk Factors – Political Uncertainty". These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, LNG plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada and uncertainty and reduced confidence in the oil and natural gas industry in western Canada.

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. See "Risk Factors – Reserve Estimates". Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. See "Risk Factors – Issuance of Debt". In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, the Corporation's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due, and the Corporation's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Corporation or at all. Similarly, there can be no assurance that the Corporation will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities.

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. See "Risk Factors – Weakness in the Oil and natural gas Industry". Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and processing and storage facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and natural gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Gathering and Processing Facilities and Pipeline Systems

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas. The Corporation's production was significantly impacted by third party restrictions during 2018.

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The Corporation's production was significantly impacted by third party restrictions during 2018. Notwithstanding the Government of Alberta's plans to purchase 7,000 rail cars and the implementation of production curtailment in Alberta, the ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Corporation's inability to realize the full economic potential of its production, or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail lines as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing for receipt of approvals of major projects remains unclear.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids, which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of rail transportation to alleviate pipeline constraints and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

During 2018, the majority of the Corporation's natural gas production in northeast British Columbia was subject to the AECO – BC Station 2 differential which was -$0.24/per GJ and fluctuated between -$1.61 per GJ and +$0.50 per GJ from 2010 to 2018. Going forward, exposure to the AECO – BC Station 2 differential is reduced as a result of the Corporation contracting capacity on the Alliance Pipeline effective May 1, 2016 for delivery of natural gas to the Chicago area.

The Corporation has contracted pipeline transportation capacity for approximately 43% of total forecasted natural gas sales volumes in 2019 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut-in if capacity is allocated to other parties.

Risks Relating to Indemnification Rights

The Corporation is subject to risks relating to certain obligations guaranteed in favour of the buyer in connection with the Tunisian Disposition which was completed on August 19, 2014.

The Corporation has guaranteed the payment of the indemnification obligations of Storm BVI under a share purchase and sale agreement with the buyer dated as of June 14, 2014. These obligations relate to claims under the agreement in respect of breaches of certain representations, warranties and covenants of Storm BVI without a limit on amount or time. Consequently, any failure by Storm BVI to pay these indemnification obligations under the agreement with the buyer could result in a substantial payment by the Corporation to the buyer, which in turn could have a material adverse effect on the Corporation's working capital and financial condition. A copy of the share purchase and sale agreement is available on the Corporation's SEDAR profile.

Political Uncertainty

The Corporation's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere.

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has begun taking steps to implement certain of its promises made during the campaign. The administration has withdrawn the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, the North American Free Trade Agreement has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the Canada – United States – Mexico Agreement which will replace NAFTA once ratified by the three signatory countries. The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom voted to withdraw from the European Union and the Government of the United Kingdom has taken steps to implement such withdrawal. The terms of the United Kingdom's exit from the European Union and whether it will occur at all remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may impact the completion of the Trans-Mountain Pipeline project, LNG facilities and other infrastructure projects.

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation and infrastructure). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas and infrastructure projects. Amendments to these controls and regulations may occur, from time to time, in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability. Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment.

In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the Competition Act and the Investment Canada Act could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows.

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial condition.

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Disposal of Fluids Used in Operations

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation.

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator.

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and natural gas companies that may be disproportionately affected by price instability. The impact and consequences of the Supreme Court of Canada's decision in the Redwater case on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings will no doubt evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees.

Climate Change

Compliance with greenhouse gas emissions regulations may result in increased operational costs to the Corporation.

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. The federal carbon levy goes into effect on April 1, 2019 and will affect provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Ontario, Manitoba, Saskatchewan and New Brunswick. The federal carbon levy will be at an initial rate of $20 per tonne. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The implementation of the federal carbon levy is currently subject to constitutional challenges submitted by the Provinces of Saskatchewan and Ontario, which are supported by the Province of New Brunswick. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironnement JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for climate-related harms.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions and increased volatility in seasonal temperatures. Extreme weather could interfere with the Corporation's production and increase the Corporation's costs. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting its operations.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves.

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and

- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to capital or being required to repay all amounts owing thereunder.

The Credit Facility is available at the discretion of the lender and may be demanded at any time. The amount authorized under the Credit Facility is dependent on the borrowing base determined by the lender from time to time. Notwithstanding the discretionary and demand nature of the Credit Facility, the Corporation is required to comply with covenants under the Credit Facility which include certain financial ratio tests and, which may, from time to time, either affect the availability, or price, of existing and/or additional funding under the Credit Facility. In the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with these covenants. A failure to comply with the applicable covenants (including the financial ratio tests) could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under the Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility imposes operating and financial restrictions on the Corporation that include restrictions on paying dividends or repurchasing or making other distributions with respect to the Corporation's securities, incurring of additional indebtedness, providing guarantees, assuming loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Corporation's lender uses the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. As a result of the depressed commodity prices experienced in the last two (2) years, the borrowing base of the Corporation's Credit Facility was reduced from $18 million to $10 million upon its scheduled re-assessment in May 2018. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed commodity prices or further reductions in commodity prices could result in a further reduction to the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness. The next scheduled semi-annual review of the Credit Facility is scheduled for May 2019. If the Corporation continues to observe lower forward commodity pricing, it is anticipated that during this scheduled re-assessment, the Corporation's lender may impose a reduction in the availability of the Credit Facility.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced.

If the Corporation's lender requires repayment of all or a portion of the amounts outstanding under the Credit Facility for any reason, including for a default of a covenant, or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under the Credit Facility, it may not be on commercially reasonable terms, or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facility, the lender under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to it to secure the indebtedness.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole, or in part, with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk.

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time, the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Reserve Estimates

The Corporation's estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;

- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation.

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Control by Principal Shareholder

The principal shareholder of the Corporation will have significant influence over the business and affairs of the Corporation.

Her Majesty the Queen in Right of the Province of Alberta ("HMQ") owns 80,357,142 Common Shares, representing approximately 36% of the current outstanding Common Shares. Alberta Investment Management Corporation ("AIMCo"), as investment manager to HMQ, maintains investment control and direction over the Common Shares for the benefit of HMQ. Accordingly, AIMCo will have significant influence over the business and affairs of the Corporation and may have the ability to take shareholder actions irrespective of the vote of any other shareholders, including the ability to prevent certain transactions that it does not believe are in HMQ's best interest. This significant influence may discourage transactions involving a change of control of the Corporation, including transactions in which minority shareholders of the Corporation might otherwise receive a premium for the Common Shares over the then-current market price.

Furthermore, AIMCo will generally have the right (subject to applicable securities laws) at any time to sell the Common Shares held by HMQ or to sell HMQ's interest in the Corporation to a third party without the approval of the minority shareholders and without providing for a purchase of such shareholders' shares. Accordingly, the Common Shares held by minority shareholders may be less liquid and worth less than they would be if AIMCo did not have the ability to influence matters affecting the Corporation.

Expiration of Licenses and Leases

The Corporation, or its working interest partners, may fail to meet the requirements of a license or lease, causing its termination or expiry.

The Corporation's properties are held in the form of licenses and leases and working interests in licenses and leases. If the Corporation or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Corporation's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation.

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and, as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on the Corporation's financial condition.

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third Party Credit Risk

The Corporation is exposed to credit risk of third party operators or partners of properties in which it has an interest.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry, generally, and of the Corporation's joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Reliance on Key Personnel

Loss of key personnel would negatively impact the Corporation's operations.

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key personnel insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact the Corporation's operations and financial position.

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage its land base, manage financial resources, analyze seismic information, administer its contracts with its operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or its competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information, or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Corporation's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Corporation's performance and earnings, as well as on its reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Management Judgment and Estimation Uncertainty

The preparation of the Financial Statements requires management judgments and estimation uncertainty that affect the reported amounts at the date of the Financial Statements of assets, liabilities, shareholders' equity, revenues and expenses in addition to the disclosure of contingencies. Actual results could differ from those estimated. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Judgments that management has made through applying accounting policies that have the most significant effect on the Financial Statements are discussed below:

Cash Generating Units

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or group of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors our operations.

Impairment (reversal) indicators

Judgments are required to assess when impairment (reversal) indicators exist and impairment (reversal) testing is required. When assessing the recoverability of petroleum and natural gas properties, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less cost to sell and value in use. In determining the recoverable amount of assets, in the absence of quoted market prices or observed market transactions, impairment tests are based on reserve estimates, market value of undeveloped lands and other relevant assumptions.

Key estimates that management has made that affect the measurement of balances and transactions are discussed below:

Reserve estimates

Petroleum and natural gas reserves are used in the calculation of depletion, impairment and impairment reversals. Reserve estimates and their resulting cash flows are based on engineering data, probability assessments of reserve recoveries, future prices and costs, future production rates, discount rates and the timing and extent of future capital expenditures, all of which are subject to many uncertainties and interpretation. We expect that over time our reserve estimates will be revised, either upward or downward, based on updated information such as the results of future drilling, testing and production levels and changes to forward petroleum and natural prices and production costs.

Decommissioning obligations

Decommissioning obligations are recognized for the future decommissioning and restoration of property, plant and equipment. These obligations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Deferred taxes

Tax interpretations, regulations and legislation in the jurisdictions in which we operate are subject to change. The deferred tax asset and/or liability is based on estimates as to the timing of the reversal of temporary differences, enacted or substantively enacted tax rates and the likelihood of assets being realized from future taxable earnings.

Adopted New Accounting Standards

Adoption of IFRS 9 "*Financial Instruments*"

Effective January 1, 2018, we adopted *IFRS 9 Financial Instruments* ("IFRS 9"), which replaced *IAS 39 Financial Instruments: Recognition and Measurement*. IFRS 9 replaced the multiple classification and measurement models for financial assets with a single model that has three classifications categories: amortized cost, fair value through profit or loss and fair value through other comprehensive income. The retrospective adoption of IFRS 9 did not have a material impact on the Financial Statements.

Adoption of IFRS 15 "*Revenue from Contracts with Customers*"

Effective January 1, 2018, we adopted *IFRS 15 Revenue from Contracts with Customers* ("IFRS 15"), which replaced *IAS 18 Revenue, IAS 11 Construction Contracts* and related interpretations. IFRS 15 provides a five-step model which includes identifying performance obligations. We applied IFRS 15 to all of our contracts with customers using the cumulative effect method. Under this method, the comparative year's financial statements have not been restated. We reviewed our customer contracts and associated revenue streams and concluded there were no material changes to the net loss or in the timing of when production revenue is recognized. As a result, no adjustments were required to the January 1, 2018 statement of financial position.

Significant Accounting Policies

A summary of our significant accounting policies are included in the notes to our Financial Statements.

New Accounting Standard Not Yet Adopted

In January 2016, the IASB issued *IFRS 16 "Leases"*. The standard requires entities to recognize lease assets and lease obligations on the statements of financial position. For lessees, there will be a single lease accounting model for all leases. There will no longer be a classification test between finance and operating leases. The lessee will recognize a right of use asset and a lease liability, and the lease will be treated as an asset on a financed basis. There will be optional exemptions from the above for short term leases, defined at 12 months or less, and leases of low value assets. There will also be an option for portfolio accounting on leases that have similar criteria. From the lessor's perspective, there will still be a dual lease accounting model that follows the criteria set out in IAS 17. As of January 1, 2019, we will be required to adopt this standard. We have compiled a list of contracts to assess the applicability of the new leasing standard. The extent of the impact of the adoption of this standard has not yet been determined.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of our disclosure controls and procedures at December 31, 2018 and have concluded that our disclosure controls and procedures are effective at December 31, 2018.

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. Our CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of our ICOFR at December 31, 2018 and have concluded that our ICOFR are effective at December 31, 2018.

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

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

Other Information

Non-GAAP Measures

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

- Adjusted funds flow (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 and provisions. We use net (debt) surplus to assist us in understanding our liquidity at specific points in time. We exclude the current portion of provisions and the deferred customer obligation as they are not financial instruments. Mark-to-market commodity contracts and assets and liabilities held for sale are excluded as they are unrealized.

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

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

Forward-Looking Statements

In the interest of providing our shareholders and readers with information regarding our company, including management's assessment of our future plans and operations, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: that the Oak Pipeline permanent replacement is expected during the first half of 2019, that we forecast minimal BC crown royalties through 2019, 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, that our rent costs will significantly decrease upon the expiration of our office lease in mid-2019, that we expect a decrease in our effective interest rate to 4.5% during the first quarter of 2019 assuming the lender's prime rate remains unchanged, that we will continue to focus on capital preservation and optionality until BC Station 2 benchmark pricing improves or we are otherwise able to secure more favorable natural gas pricing, that our previous capital program has put us in an excellent position to accelerate activity when commodity prices recover, that our future production will benefit from the commissioning of our Birley facility expansion, that our Aitken Creek Pipeline provides us optionality upon the future development of a gas plant, that we could secure further commodity marketing contracts, that TCPL's North Montney expansion will be completed in 2019 or 2020, the estimated effects on our operations caused by the rupture of one of the T-South Pipelines, how we intend to manage our company and that we may voluntarily shut-in volumes throughout 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 2018, which is subject to the discretion of our Board of Directors, will not be amended in the future, and the continued availability of adequate debt and cash flow to fund our planned expenditures. Although we believe that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, anticipated third party restrictions, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, our Board of Directors may amend the capital program for 2019 based on its discretion; environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increases in or unforeseen capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Future Oriented Financial Information

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

Selected Definitions and Abbreviations

Oil and Natural Gas Liquids

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.