2016 Management's Discussion and Analysis

CHINOOK energy inc

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. ("CEI") and its subsidiaries, both wholly and partially owned, (collectively, "our", "we" or "us") for the three months and year ended December 31, 2016 and 2015 and should be read in conjunction with our audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2016 and 2015 (the "Financial Statements"). This MD&A is based on information available as at March 23, 2017.

The term "fourth quarter" and "reported year" or similar terms are used throughout this document and refer to the three months and year ended December 31, 2016, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three months and year ended December 31, 2016, in this respective order. The term "same period(s) of 2015" and "comparative period(s)" or similar terms are used throughout this document and refer to the three months or (and) year ended December 31, 2015, in this respective order, depending on the 2016 period(s) under discussion.

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

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2016 ("AIF"), 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 with the exception of Craft Oil Ltd. ("Craft"). Our accounts and operating results include those of Craft from June 10, 2016, the date we acquired 70% of the common shares in a predecessor of this company to December 12, 2016, the date that our shareholdings in Craft were distributed to our shareholders as at the close of business (see "Acquisition of Craft" and "Distribution of Craft Shares to Our Shareholders" for further details). Subsequent to December 12, 2016, Craft is not required to be consolidated into our financial and operating results as our control of Craft's operations ceased on this date. For the period(s) from June 10, 2016 to December 12, 2016, we adjusted for the minority interest share in the financial accounts of Craft through the non-controlling interest on the consolidated statements of operations and comprehensive loss. In this MD&A we do not adjust for the non-controlling interest in Craft's production volumes.

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 crude oil, natural gas liquids and natural gas. We are focussed 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.

Strategic Acquisition and Craft Share Distribution

On June 10, 2016 (the “Closing Date”), we conveyed the majority of our Alberta oil and natural gas assets, excluding our Montney assets, and the associated decommissioning obligations in addition to $0.9 million cash (collectively, the "Subject Assets") to Tournament Exploration Ltd., a predecessor of Craft, a private Calgary-based petroleum and natural gas production company, for 70% of its issued and outstanding common shares pursuant to an asset purchase and sale agreement dated and effective May 1, 2016 (the "PSA").

On December 12, 2016, we completed the distribution of all of the Craft shares held by us to our shareholders as at the close of business pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "Craft Share Distribution"). Following the Craft Share Distribution, our control over Craft’s operations ceased. As a result, for any period(s) subsequent to December 12, 2016, the accounts of Craft are not reflected in our financial and operating results.

Non-Core Asset Dispositions

On January 4, 2017, we announced the completion of a review of strategic alternatives, initiated on August 2, 2016, resulting in two agreements to sell certain of our petroleum and natural gas properties and undeveloped lands located in the Knopcik/Pipestone and East Gold Creek areas of northwestern Alberta for total net proceeds of $18.0 million, subject to closing adjustments. At December 31, 2016, these properties were classified as held for sale as it was highly probable that their carrying value would be received through a sales transaction rather than through continued use. The held for sale properties are 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). These transactions have since closed. The gain on disposition of properties of $11.0 million will be recognized in our 2017 first quarter financial results.

Financial and Operating Highlights

	Three months ended December 31		Year ended December 31	
	2016	2015	**2016**	2015
OPERATIONS				
Production (1)				
Crude oil (bbl/d)	**451**	922	**768**	1,187
Natural gas liquids (boe/d)	**613**	364	**637**	510
Natural gas (mcf/d)	**21,548**	15,851	**24,631**	23,642
Average daily production (boe/d)	**4,655**	3,928	**5,510**	5,637
Sales Prices				
Average oil price ($/bbl)	**$ 71.98**	$ 47.93	**$ 52.01**	$ 53.08
Average natural gas liquids price ($/boe)	**$ 40.70**	$ 30.59	**$ 26.35**	$ 35.83
Average natural gas price ($/mcf)	**$ 3.31**	$ 2.09	**$ 2.06**	$ 2.50
Netback (2)				
Average commodity pricing ($/boe)	**$ 27.67**	$ 22.51	**$ 19.51**	$ 24.89
Royalties ($/boe)	**$ (2.84)**	$ 2.39	**$ (1.19)**	$ (0.73)
Net production expenses ($/boe) (2)	**$ (11.88)**	$ (14.17)	**$ (13.61)**	$ (15.92)
G&A expense ($/boe)	**$ (5.80)**	$ (8.31)	**$ (4.58)**	$ (4.76)
Netback ($/boe) (2)	**$ 7.15**	$ 2.42	**$ 0.13**	$ 3.48
Wells Drilled (net)				
Total natural gas wells drilled (net)	**2.63**	-	**2.63**	2.75
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 10,631**	$ 9,000	**$ 36,943**	$ 49,701
Funds (Outflow) from operations (2)	**$ 1,713**	$ 1,516	**$ (1,004)**	$ 9,033
Per share - basic & diluted ($/share)	**$ 0.01**	$ 0.01	**$ (0.00)**	$ 0.04
Net income (loss)	**$ 6,427**	$ (5,303)	**$ (54,773)**	$ (83,606)
Per share - basic and diluted ($/share)	**$ 0.03**	$ (0.02)	**$ (0.25)**	$ (0.39)
Capital expenditures	**$ 4,177**	$ 9,998	**$ 9,211**	$ 44,325
Net surplus (2)	**$ (15,138)**	$ (29,614)	**$ (15,138)**	$ (29,614)
Total assets	**$ 139,975**	$ 321,564	**$ 139,975**	$ 321,564
Common Shares (thousands)				
Weighted average during period				
- basic	**216,443**	215,337	**215,860**	215,197
- diluted	**216,621**	215,337	**215,860**	215,197
Outstanding at period end	**216,443**	215,349	**216,443**	215,349

(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) 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.

Acquisition of Craft

On the Closing Date, we conveyed the Subject Assets to Craft pursuant to the PSA. The purpose of this business acquisition was to consolidate similar Alberta non-Montney properties with sufficient associated reserves to attract additional financing and have a management team focused on the development of these properties. Craft properties included Willisden Green and Ferrier, located in west central Alberta, prospective for Cardium light oil and natural gas. The Subject Asset properties included non-Montney Albright and Beaverlodge prospective for Dunvegan and Doe Creek, Gold Creek and Pipestone, in addition to Valhalla, Sinclair, Gordondale and Boundary Lake South. The Subject Assets also included primarily all of our properties located in West Central Alberta and Plains.

Concurrent with our contribution of the Subject Assets to Craft, WOGH Limited Partnership ("WOGH") contributed producing and undeveloped properties in similar areas net of associated decommissioning obligations and cash to acquire 10% of Craft's issued and outstanding common shares pursuant to the PSA. WOGH is a partnership principally managed by Alberta Investment Management Corporation, a related party to us. As the issuance of Craft's common shares to us and WOGH was evaluated on the fair value of contributed net assets of each transacting party relative to the total fair value, we sequenced this business acquisition to already include WOGH's contribution of net assets. As a result, the fair value of net assets acquired by us includes both of those contributed from Craft and WOGH.

Fair Value of Craft's Net Assets

Since Craft was a private company and the fair value of this company's common shares was not available from market transactions, we evaluated the fair value of Craft's net assets as at the Closing Date. This evaluation included evidence from the agreed upon consideration for those properties and associated decommissioning obligations. The details of the fair value amounts of Craft's net assets as at the Closing Date were evaluated as follows:

Development & production assets: this fair value was approximated using an internally prepared reserve evaluation. This evaluation uses future cash flows anticipated to be produced from Craft's proved developed producing reserves and the selling price obtained on its October 2016 disposition of certain properties.

Exploration & evaluation assets: this fair value was approximated using recent market sales transactions of similar undeveloped lands in the immediate surrounding areas.

Decommissioning obligations: this fair value was determined using the timing and estimated costs associated with the abandonment, restoration and reclamation of proved developed wells and infrastructure and then present valued using a market discount rate.

Debt: this fair value was determined to approximate the outstanding principal amount.

Other financial instruments: the carrying values of other financial instruments approximate their fair values.

Non-controlling interest: the above fair value measures were used to calculate the Closing Date fair value of the 30% non-controlling interest in Craft.

CEI's Consideration

As we maintained control over the Subject Assets transferred to Craft after this acquisition, we continued to measure the Subject Assets at the same carrying amounts immediately prior to and after the acquisition. This resulted in the Subject Assets' carrying value at the Closing Date being used to determine the 30% non-controlling interest. An evaluation of the fair value of the D&P assets' component of the Subject Assets revealed that their fair value less costs to sell was less than their carrying amount. As a result, we adjusted for the non-controlling interest portion of this loss through an adjustment to equity of $25.4 million.

Business Combination

A summary of the business combination is as follows:

		June 10, 2016
Estimated fair value of net assets acquired:		
Working capital	$	2,081
Development and production assets		23,600
Exploration and evaluation assets		1,300
Bank debt		(17,793)
Decommissioning obligations		(3,977)
Non-controlling interest		(1,563)
	$	3,648
Estimated consideration:		
Non-controlling interest in the carrying value of the Subject Assets	$	29,066
Equity loss		(25,418)
	$	3,648

The production and operational netback results during the fourth quarter for CEI and October 1, 2016 to December 12, 2016 for Craft are as follows:

		CEI		Craft		Total
Production						
Crude oil (bbl/d)		35		416		451
Natural gas liquids (boe/d)		309		304		613
Natural gas (mcf/d)		13,494		8,054		21,548
Average daily production (boe/d)		2,593		2,063		4,655
Operational Netback (1)						
Average commodity pricing ($/boe)	$	20.16	$	37.09	$	27.67
Royalties ($/boe)	$	(1.23)	$	(4.86)	$	(2.84)
Net production expenses ($/boe) (1)	$	(9.39)	$	(15.00)	$	(11.88)
Operational Netback ($/boe) (1)	$	9.54	$	17.23	$	12.95

(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.

Distribution of Craft Shares to Our Shareholders

To measure the distribution of Craft shares, we estimated the fair value of each line item that comprised Craft's net assets as at December 12, 2016. Subsequent to December 12, 2016, Craft entered into purchase and sales agreements to dispose of substantially all of its petroleum and natural gas properties. The selling price in these agreements was used as a basis to estimate the fair value of these properties, net of decommissioning obligations. Upon comparing the carrying value to the fair value of Craft's properties, an additional impairment charge of $6.1 million was recognized. Relative to our fair value measure of Craft's properties, net of decommissioning obligations, as previously measured as at September 30, 2016, this fourth quarter impairment charge was the direct result of a 25% decrease to a purchaser's closing share value from its deemed share value included as a component of the consideration Craft received pursuant to a purchase and sales agreement.

A summary of the estimated fair value of Craft's net assets distributed to our shareholders as at December 12, 2016 is as follows:

		December 12, 2016
Estimated fair value of Craft's net assets distributed to Chinook's shareholders:		
Cash	$	8,220
Non-cash working capital, excluding the fair value of commodity price contracts and third party warrants		(711)
Commodity price contracts and third party warrants		(4,254)
Bank debt		(6,287)
Development & production and exploration & evaluation assets, net of decommissioning obligation		37,003
Non-controlling interest		(10,004)
	$	23,967

We recognized the fair value of 152,251,953 Craft shares distributed to our shareholders as at December 12, 2016 through a $24.0 million charge directly to our deficit. On a net asset fair value basis, this equates to $0.16 per distributed Craft share.

Comparison of Fourth Quarter Guidance to Actual Results

The following table provides a comparison of our fourth quarter guidance as announced on November 9, 2016 and our actual results:

($ millions, except boe/d)	Fourth Quarter Guidance (1)	Fourth Quarter Actuals (2)
Average production (boe/d)	2,983	2,593
Exit production (boe/d)	3,482	3,030
Capital expenditures	$ 5.5	$ 4.2
Net surplus (3)	$ 13.0	$ 15.1

(1) Our guidance for our 2016 fourth quarter is pro-forma the Craft Share Distribution (assuming such Craft Share Distribution was effective October 1, 2016).
(2) Fourth quarter actual results exclude Craft's results from October 1, 2016 to the date of the completion of the Craft Share Distribution on December 12, 2016.
(3) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Our fourth quarter guidance was provided on an unconsolidated basis on anticipation of the Craft Share Distribution as subsequently completed on December 12, 2016. CEI's average production during the fourth quarter was lower than guidance as a result of a delay in restarting our Boundary Lake North field of northwestern BC. This field was expected to resume production at 375 boe/d in December 2016 but was delayed until January 2017. In addition December's downtime due to cold weather and third party facility downtime resulted in lower production of 550 boe/d. Our fourth quarter capital expenditures were lower than our guidance due to drilling three (2.63 net) Birley/Umbach wells at approximately 26% under budget with average drilling costs of approximately $1.28 million per well ($1.12 million, net). This resulted in an improvement of the December 31, 2016 net surplus compared to guidance. It is anticipated that this surplus, in addition to non-core property dispositions completed during the first quarter of 2017 and funds flow, will fund our $40 million 2017 capital program. See "Capital Resources, Capital Expenditures and Liquidity".

Operations

Petroleum and Natural Gas Production Volumes

	Three months ended December 31		Year ended December 31	
	2016	2015	**2016**	2015
Crude oil (bbl/d)	**451**	922	**768**	1,187
Natural gas liquids (boe/d)	**613**	364	**637**	510
Natural gas (mcf/d)	**21,548**	15,851	**24,631**	23,642
Total (boe/d)	**4,655**	3,928	**5,510**	5,637

Total Production Volumes

During mid-February 2016, we brought on-stream three (2.75 net) additional wells at Birley/Umbach upon the commissioning of our new compression facility. Currently, we have production from eight wells (6.87 net) in this area and have the capacity to add the volumes from a ninth standing well (0.75 net). Three of these wells (2.63 net) were drilled in December 2016 and then completed and tested prior to being brought on-stream late in the first quarter of 2017. The a-71-F (0.75 net), d-95-F (0.98 net) and c-95-F (0.90 net) wells averaged gross test gas rates of 7,319 mcf/d, 6,756 mcf/d and 8,202 mcf/d during the last 24 hours of testing with free condensate to gas ratios of 8 bbl/mmcf, 11 bbl/mmcf and 25 bbl/mmcf, respectively. We also reactivated our Boundary Lake North field located in northeastern BC which has increased our production volumes by 400 boe/d for 2017 through to the date of this MD&A.

Our production volumes during the current reporting periods from our Birley/Umbach properties were approximately 1,300 boe/d and 1,625 boe/d, respectively, increases of 1,050 boe/d compared to the same periods of 2015. Our fourth quarter production volumes at Birley/Umbach were constrained by a third party plant restriction, extreme cold weather and a temporary shut-in due to depressed Station 2 pricing. Included in our reported year production volumes from the Closing Date to October 2016 are Craft's legacy properties, excluding the Subject Assets, of 2,000 boe/d of production. In October 2016, Craft sold these legacy properties in addition to certain properties included in the Subject Assets for consideration of $13.5 million comprised of $9.0 million in cash and $4.5 million in third party units. As previously discussed, on December 12, 2016, we completed the Craft Share Distribution. The decrease in volumes from the Subject Assets, when combined with the shut-in of both third party plants and production volumes in response to continued depressed Station 2 pricing resulted in the reported year's decrease of 127 boe/d compared to the same period of 2015. Last year's voluntary shut-in of relatively higher operating cost/lower netback wells, began early in the second quarter of 2015 and remained shut-in throughout the reported year. For the comparative year, production from these areas averaged 245 boe/d. These wells are mostly located in BC on our Hoffard, Rigel, Boundary Lake North and non-Montney East Gold Creek properties. The non-Montney East Gold Creek property was sold in the second quarter of 2016 for $10.4 million of cash consideration with associated production of 100 boe/d. The 2015 disposition of the predominantly crude oil Rainbow property with associated production of 183 boe/d also contributed to the reported year decrease in production volumes.

In addition to increased volumes during the current reported periods from our Birley/Umbach area, compared to the same periods of 2015, improved commodity pricing and a new gas handling agreement enabled us to reactivate wells in Martin Creek and Black Conroy areas in northeastern BC resulting in 1,100 boe/d of production during the fourth quarter. This contributed to an increase in production of 727 boe/d during the fourth quarter compared to the same quarter of 2015.

Natural Gas and Natural Gas Liquids Production ("NGL") Volumes

Natural gas and its associated liquids production for the current reporting periods increased compared to the same periods of 2015 as a result of our recent Birley/Umbach area development program, the reactivation of wells in Martin Creek and Black Conroy, BC, and the acquisition of Craft, excluding the Subject Assets. The fourth quarter natural gas and NGL production from our portfolio of producing properties held on December 31, 2016, was 13,494 mcf/d and 309 boe/d, respectively. This excludes the volumes brought on-stream during the first quarter of 2017 from our December 2016 three well (2.63 net) drilling program and the reactivation of our Boundary Lake North property.

Crude Oil Production Volumes

Our crude oil production volumes for the current reporting periods decreased by 471 bbl/d and 419 bbl/d compared to the same periods of 2015. During the reported year, we focused on our transformation into a pure Montney play focused on liquids-rich natural gas in our Birley/Umbach area. Consequently, our crude oil production has decreased during the current reporting periods compared to the same periods of 2015. Also contributing to these decreases was lower crude oil volumes from the Subject Assets resulting from both property dispositions and the Craft Share Distribution. The reported year decrease was also caused by pipeline service restrictions in the Grande Prairie area, last year's disposition of the predominantly crude oil Rainbow property and natural production declines. Our fourth quarter crude oil production from the portfolio of producing properties we held on December 31, 2016, was 35 bbl/d.

Petroleum and Natural Gas Revenues and Realized Pricing

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2016**	2015	**2016**	2015
Oil sales	**$ 2,986**	$ 4,066	**$ 14,619**	$ 22,997
$/bbl	**71.98**	47.93	**52.01**	53.08
Natural gas liquids sales	**$ 2,296**	$ 1,025	**$ 6,147**	$ 6,671
$/boe	**40.70**	30.59	**26.35**	35.83
Natural gas sales	**$ 6,567**	$ 3,044	**$ 18,578**	$ 21,538
$/mcf	**3.31**	2.09	**2.06**	2.50
Petroleum & natural gas revenue	**$ 11,849**	$ 8,135	**$ 39,344**	$ 51,206
$/boe	**27.67**	22.51	**19.51**	24.89

Our petroleum and natural gas revenues increased for the fourth quarter while decreasing for the reported year compared to the same periods of 2015. This fourth quarter increase was the result of higher benchmark pricing and increased natural gas and NGL volumes due to well reactivations and production brought on-stream as a result of our development of the Birley/Umbach area. Inversely, this reported year decrease was caused by both lower crude oil sales volumes and realized commodity pricing. The lower crude oil volumes were due to our focus on Montney liquids rich natural gas, dispositions and pipeline capacity restrictions which affected our former

Subject Assets. The decrease in our realized commodity pricing for the reported year was due to lower benchmark pricing which began to decline during the fourth quarter of 2014, before showing improvement late in the third quarter of 2016, in addition to a decrease in the ratio of the comparatively higher priced crude oil production volumes relative to total sales volumes. This ratio decreased to 14% during the reported year from 21% during the comparative period of 2015. The reported year's average commodity price decrease, compared to the same period of 2015, was partially offset by an increase in the proportion of NGL volumes as a result of the focus on our liquid rich natural gas Birley/Umbach property.

During the reported year, on a request from the operator, the BC Government reclassified a natural gas well to crude oil resulting in prior years' adjustments. Had these adjustments not been made, our revenue and pricing for crude oil for the reported year would have been $13.3 million or $47.38/bbl. Similarly, the revenues and pricing for natural gas liquids for the reported year would have been $7.4 million or $31.94/boe.

Benchmark Prices

	Three months ended December 31		Year ended December 31	
	2016	2015	**2016**	2015
Crude oil				
Canadian light sweet [1] ($/bbl)	**$ 60.76**	$ 52.55	**$ 52.80**	$ 57.45
Natural gas liquids				
WTI [2] ($US/bbl)	**$ 49.29**	$ 42.18	**$ 43.32**	$ 48.80
Natural gas				
AECO gas [3] ($/mcf)	**$ 3.11**	$ 2.50	**$ 2.18**	$ 2.59
BC Westcoast Station 2 ($/mcf)	**$ 2.38**	$ 1.11	**$ 1.75**	$ 1.81

(1) Central market point for Canadian crude oil
(2) West Texas Intermediate – Central market point for US crude oil
(3) Central market point for Canadian natural gas

Crude Oil Pricing

Our fourth quarter crude oil realized price of $71.98/bbl is higher than the associated benchmark pricing. During the fourth quarter, we lowered our estimated third quarter Craft crude oil production volumes. Given those volumes had a lower associated price, the effect of this change in estimate was to increase our fourth quarter realized price. Further, after adjusting for this and the well reclassification as described above, our adjusted current reported periods realized crude oil price was $57.60/bbl and $46.10/bbl, compared to $47.93/bbl and $53.08/bbl for the same periods of 2015. Our conventional crude oil production is sold at prices based on the Canadian light sweet benchmark postings adjusted for quality. This benchmark price increased during the fourth quarter compared to the same quarter of 2015 but decreased during the reported year compared to the same period of 2015, as did our adjusted average realized crude oil prices.

NGL Pricing

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 or WTI. During the fourth quarter, consistent with the increase in the Canadian light sweet oil benchmark, our realized NGL price of $40.70/boe increased compared to $30.59/boe for the same quarter of 2015. Inversely, during the reported year, after adjusting for the well reclassification as described above, consistent with the decrease in the Canadian light sweet oil benchmark, our adjusted realized NGL price of $31.94/boe decreased compared to $35.83/boe for the same period of 2015. Chinook's on-going operations realized NGL price in the current reported periods was $44.30/boe and $26.57/boe.

The ratio of our adjusted NGL price relative to Canadian light sweet oil was 67% and 60% for the current reporting periods compared to approximately 60% for the same periods of 2015. The higher fourth quarter ratio was caused by the price of propane increasing at a greater rate than the increase in the Canadian light sweet benchmark in addition to an increase in our condensate rich production volumes from Birley/Umbach.

Natural Gas Pricing

Our realized natural gas price of $3.31/mcf during the fourth quarter increased compared to $2.09/mcf for the same quarter of 2015. This increase was consistent with higher AECO and Station 2 benchmark pricing.

Our realized natural gas price of $2.06/mcf for the reported year decreased from $2.50/mcf for the same period of 2015. This decrease was due to both an increase in the ratio of our production from BC in addition to lower benchmark pricing. This downward price pressure on our BC production was caused by Station 2 pricing which decreased starting in February and continued until it started to recover in the third quarter of 2016.

During the second quarter of 2016, we started flowing firm capacity that sold at Alliance Chicago pricing. From the time we entered into the agreement to the end of the reported year, approximately 36% of our BC production was sold at this hub point at an average price of $2.11/GJ which was a $0.20/GJ premium relative to the Station 2 pricing that we received on the remainder of our BC production.

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2016**	2015	**2016**	2015
Royalties	**$ 1,218**	$ (865)	**$ 2,401**	$ 1,505
Per sales ($/boe)	**$ 2.84**	$ (2.39)	**$ 1.19**	$ 0.73
Percent of revenues (%)	**10.3**	(10.6)	**6.1**	2.9

For the current reporting periods, our royalties increased on an overall basis, per boe and as a percentage of revenue, compared to the same periods of 2015. These increases primarily resulted from adjustments during the comparative periods to our Gas Cost Allowance that included a fourth quarter of 2015 adjustment of approximately $1.5 million. In addition, during the fourth quarter our overall royalties increased as a result of higher commodity pricing and sales volumes.

For future reporting periods, with our focus on the development of our Montney play in the Birley/Umbach area increasing the proportion of our production from BC which has relatively lower associated royalty rates, we anticipate a decrease in our overall royalty rate.

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 funds flow. This provides more certainty within determined commodities price ranges as to what we will receive on a portion of our crude oil 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. We continuously review the need to utilize such financing strategies.

Our unsettled swap commodity price contracts 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 as compared to our received price multiplied by the remaining notional volumes. Volatility in the commodity price and any decrease 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 periods are recognized in net income (loss) as unrealized gains or losses on commodity price contracts. Realized gains or losses from these financial commodity price contracts are recognized in net income (loss) over their term.

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

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Realized losses (gains) on commodity price contracts	**$ 151**	$ (455)	**$ (1,010)**	$ (1,587)
Unrealized losses on commodity price contracts	**2,766**	391	**4,695**	1,481
Total	**$ 2,917**	$ (64)	**$ 3,685**	$ (106)

During the current reporting periods, the unrealized and realized losses (gains) substantially resulted from contracts held by Craft. We estimated Craft's commodity price contracts to have a fair value liability of $4.5 million on December 12, 2016. This fair value estimate was included in Craft's net assets as used to measure the value of Craft shares distributed to our shareholders (see "Distribution of Craft Shares to Our Shareholders").

In the fourth quarter, Chinook entered into the following commodity price contract which had an estimated fair value current liability of $0.2 million with the following terms:

Indexed Price	Notional Volumes	Company's Received Price	Remaining Contractual Term
AECO	7,500 GJ/d	$3.205/GJ	January 1, 2017 to December 31, 2017

Subsequent to December 31, 2016, we entered into a commodity price contract with the following terms:

Indexed Price	Notional Volumes	Company's Received Price	Contractual Term
AECO	4,000 GJ/d	$2.50/GJ	April 1, 2017 to October 31, 2017

With the combined notional volumes from the above two outstanding commodity price contracts, we will receive a weighted average price of $3.04/GJ on approximately 42% of our forecasted natural gas production volumes.

Production and Operating Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2016**	2015	**2016**	2015
Production & operating	**$ 5,256**	$ 6,529	**$ 29,618**	$ 36,628
Less:				
Processing & gathering revenues	**(168)**	(1,407)	**(2,178)**	(3,873)
Net production & operating expense [(1)]	**$ 5,088**	$ 5,122	**$ 27,440**	$ 32,755
Per sales net production & operating expenses ($/boe) [(1)]	**$ 11.88**	$ 14.17	**$ 13.61**	$ 15.92
Per sales production & operating expenses ($/boe)	**$ 12.27**	$ 18.07	**$ 14.69**	$ 17.80

(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.

Production and operating expense for the current reporting periods decreased in total and on a boe basis from the same periods of 2015. These decreases were due to the October 2016 disposition of certain Subject Assets, with their relatively higher operating costs on a boe basis, and to a lesser extent the Craft Share Distribution.

The decreases in total operating costs and on a boe basis for the reported year, compared to the same period of 2015, also resulted from the disposition of higher operating cost properties, most notably Rainbow. Also contributing to this decrease was last year's voluntary shut-in of relatively higher operating cost/lower netback wells, which began early in the second quarter of 2015 and remained shut-in throughout the reported year. These wells are mostly located in BC on our Hoffard, Rigel, Boundary Lake North and non-Montney Gold Creek properties. The non-Montney Gold Creek property was sold in the second quarter of 2016 for $10.0 million of cash consideration. Although reported year production from these areas decreased by approximately 245 boe/d, having them shut-in resulted in reductions in total production and operating costs of $2.1 million, which also reduced our cost on a per boe basis. We also realized cost saving initiatives implemented in 2015 principally through optimization of field staff and lower costs for hauling, chemicals, repairs and maintenance without compromising our commitment to health and safety.

On a per boe basis, for the same reasons as just discussed, operating costs decreased during the reported year compared to the same period of 2015. Although we increased our volumes at Birley/Umbach and this added to our total operating costs, the synergies achieved through these incremental volumes had the effect of decreasing our operating costs in this area.

During the fourth quarter, we began to see the benefits realized by a gas handling agreement which we executed late during the third quarter of 2016 and which impacts the majority of our BC natural gas production. It has significantly improved go-forward drilling economics, bringing base production back online and providing gas handling capacity for growth volumes as well as reducing operating costs by approximately $2.70/boe on our on-going properties. Early in the first quarter of 2017, these improved economics allowed us to reactivate our Boundary Lake North property with 400 boe/d of associated production volumes. We further expect our 2017 on-going operations to incur production costs under $10/boe.

The current reporting periods processing and gathering revenue decreased compared to the same periods of 2015. The bulk of these revenues resulted from processing and gathering assets included in the Subject Assets. For the reported year, in comparison to the same period of 2015, this decrease was the result of lower third party volumes that flowed through our processing facilities and distribution lines. These lower revenues correspond to areas where we had shut-in volumes during 2015 in response to decreased commodity pricing. The associated processing and gathering costs as reported through operating costs correspondingly also decreased. The decrease in the fourth quarter, compared to the same quarter of 2015, also resulted from the sale of the majority of Craft's processing and gathering facilities in October 2016. Also, during the fourth quarter of 2015 we reported favorable operating partners' equalization of processing and gathering revenues.

General & Administrative ("G&A") Expense

	Three months ended December 31		**Year ended December 31**	
($ thousands, except where noted)	**2016**	2015	**2016**	2015
G&A expense	**$ 2,484**	$ 3,002	**$ 9,235**	$ 9,797
Per sales ($/boe)	**$ 5.80**	$ 8.31	**$ 4.58**	$ 4.76

We have focused on improving our G&A cost structure through cost cutting initiatives and we continue to assess our G&A expenses and make reductions where feasible. As a result of lower staffing costs due to reductions in headcount, a planned temporary work week reduction, reduced officers' and directors' compensation, reduced employee benefits and less reliance on consultants, our reported year's G&A expense overall and on a per boe basis decreased compared to the same period of 2015. During the first quarter of 2017, we have made further reductions in our headcount. Partially offsetting these decreases to our overall G&A were $1.6 million of Craft G&A costs from June 10, 2016 to December 12, 2016. During the reported year, $2.4 million of our total G&A related to rent expense incurred on our head office lease which expires June 30, 2019, see "Commitments and Guarantee". Assuming current rental market conditions remain the same or similar, we expect a favourable rent adjustment commencing in 2019 upon our lease expiration, based on our anticipated office space requirements.

For the foregoing reasons, our G&A expense decreased overall and on boe basis during the fourth quarter, compared to the same quarter of 2015. Although personnel were transferred to Craft on conveyances of the Subject Assets, this significant G&A cost reduction will not be fully realized until the first quarter of 2017.

Netback

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

	Three months ended December 31		Year ended December 31	
Per sales ($/boe)	**2016**	2015	**2016**	2015
Realized sales price	**$ 27.67**	$ 22.51	**$ 19.51**	$ 24.89
Less:				
Royalties	**(2.84)**	2.39	**(1.19)**	(0.73)
Net production expense [1]	**(11.88)**	(14.17)	**(13.61)**	(15.92)
G&A expense	**(5.80)**	(8.31)	**(4.58)**	(4.76)
Netback [1]	**$ 7.15**	$ 2.42	**$ 0.13**	$ 3.48

(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 netback increased for the fourth quarter compared to the same quarter of 2015. This increase resulted from improved commodity pricing combined with, on a boe basis, lower net production and G&A expenses. These changes have been previously discussed.

For the reported year, the decrease in the proportion of crude oil sales relative to our total volumes was caused by higher natural gas production, with an increase in associated liquids, from our recent development program at our Birley/Umbach area and dispositions of crude oil properties late in 2015 and during 2016. Generally, crude oil sales have had a higher netback than on an equivalent volume of natural gas as determined from its heating value. This change in the proportion of crude oil sales partly caused decreases to our realized prices, which then resulted in an unfavorable netback. Fortunately, the lower commodity pricing for the reported year was partially offset by a combined $2.49/boe decrease in net production and G&A expenses.

Craft Transaction and Distribution Costs

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Transaction & distribution costs	**$ 1,422**	$ -	**$ 3,162**	$ -

Expensed transaction costs incurred in respect of the Craft acquisition include legal and other professional fees in addition to severance costs. When combined with the costs for the Craft Share Distribution, as mostly incurred during the fourth quarter, the total transaction and distribution costs were $1.4 million and $3.2 million for the current reporting periods.

Exploration and Evaluation Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Exploration & evaluation expenditures	**$ (239)**	$ 731	**$ 729**	$ 1,648

Exploration and evaluation expense reported during the current and the comparative periods were due to salaries, pre-licensing evaluation and exploratory lease rental costs. During the fourth quarter we sold $0.3 million of seismic data to a third party and reported a corresponding recovery through exploration and evaluation expense.

Realized Loss on Sale of Notes

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Realized loss on sale of notes	**$ 648**	$ -	**$ 648**	$ -

In October 2016, Craft disposed of properties for proceeds of $13.5 million. Consideration that Craft received for this disposition included $4.5 million of the buyer's units (the "Units"). The Units were comprised of par value 10.5% senior secured notes (the "Notes") due in 2021 and 7.38 million purchase warrants (the "Warrants"). Each Warrant entitles the holder to acquire one common share of the buyer at a price of $0.18 per share. The Warrants expire November 15, 2021. We bifurcated the value of the Units between the Notes and the Warrants. The fair value of the Warrants was estimated using received bids. The fair value of the Notes was determined from the face value of the Units less the estimated fair value of the Warrants. Our fair value estimates for the Notes and Warrants was $4.2 million and $0.3 million, respectively.

In November 2016, Craft sold all of the Notes for $3.6 million. This resulted in a realized loss on the sale of $0.6 million.

Impairment of Development & Production and Exploration & Evaluation Assets, Net of Reversal

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2016**	2015	**2016**	2015
Impairment of development & production and exploration & evaluation assets, net of recovery (recovery)	**$ (10,900)**	$ -	**$ 41,100**	$ 75,000

Evaluation of Composition of Cash Generating Units

We reviewed and adjusted our Cash Generating Units ("CGUs") as a result of changes to our property mix achieved through core area development, significant property dispositions and the Craft Share Distribution on December 12, 2016. Our petroleum and natural gas properties are located in the Peace River Arch area with a commodity mix weighted to natural gas and its associated liquids. We concluded that we had one CGU, the Peace Arch River area, as at December 31, 2016.

Impairment of Development & Production Assets

We evaluated the consideration received on a disposition of certain of Craft's properties in October 2016 and concluded that this was evidence that there was a decrease in the fair value of the Subject Assets. This evidence warranted conducting an impairment test on the Craft CGU's carrying value. As the consideration received in October 2016 approximated the future cash flows anticipated to be produced from proved developed producing reserves, using a before income tax discount rate of 15 percent and forward commodity price estimates, we applied these same metrics to estimate the fair value less costs to sell of the Craft CGU. This estimate resulted in an impairment charge of $52.0 million.

The September 30, 2016, proved producing reserves of the Craft CGU were estimated internally by us based on an independent reserve report effective December 31, 2015 and operational events to September 30, 2016.

The calculation of the Craft CGU's fair value less costs to sell used the following forward commodity prices, as estimated by us, at September 30, 2016:

As at September 30, 2016	**Edmonton light ($/bbl)**	**AECO Gas ($/mmbtu)**
2016 (3 months)	$ 50.74	$ 2.56
2017	$ 66.40	$ 3.20
2018	$ 72.80	$ 3.55
2019	$ 80.90	$ 3.85
2020	$ 83.20	$ 3.95
Thereafter	1.94% to 2.07%/yr	1.6% to 3.77%/yr

On distribution of the Craft shares to our shareholders, and as previously discussed, we recognized an additional impairment charge of $6.1 million. The combined impairment charge was $58.1 million for the period from June 10, 2016 to December 12, 2016.

Reversal of Prior Years' Impairment of Development & Production Assets

As at December 31, 2016, we observed evidence that warranted a test for impairment or reversal of the one remaining CGU's carrying value relative to its recoverable value. We determined the December 31, 2016 recoverable value to be fair value less cost to sell as estimated to be $93.0 million. As the Peace River Arch CGU's recoverable amount was higher than its carrying value, this resulted in a $17.0 million reversal of prior years' impairment expense.

The Peace River Arch CGU's recoverable amount was based on an independently prepared reserve report effective December 31, 2016. We used this report to calculate expected future cash flows anticipated to be produced from the combined reserve categories proved developed producing, non-producing/undeveloped and probable using before income tax discount rates of 15%, 20% and 30%, as respectively applied to each reserve category, in addition to the following forward commodity price estimates:

	Edmonton Light Crude Oil ($/bbl) (1)		AECO Gas ($/mmbtu) (2)	
As at December 31,	**2016 (3)**	**2015 (3)**	**2016 (3)**	**2015 (3)**
2017	$ 69.80	$ 66.40	$ 3.40	$ 3.20
2018	$ 72.70	$ 72.80	$ 3.15	$ 3.55
2019	$ 75.50	$ 80.90	$ 3.30	$ 3.85
2020	$ 81.10	$ 83.20	$ 3.60	$ 3.95
2021	$ 86.60	$ 88.20	$ 3.90	$ 4.20
Thereafter	2%	2%	2%	2%

(1) Central market point for Canadian crude oil.
(2) Central market point for Canadian natural gas.
(3) Source: McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2017 and 2016.

Impairment of Development & Production and Exploration & Evaluation Assets, Net of Reversal

For the current reporting periods, Craft's impairment expense was $6.1 million and $58.1 million. Combined with the current reporting periods' $17.0 million reversal of prior years' impairment expense from our one remaining CGU, the impairment of developed & production ("D&P") assets and exploration & evaluation ("E&E") assets, net of reversal, for the current reporting periods was a recovery of $10.9 million and an impairment of $41.1 million.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2016**	2015	**2016**	2015
Depletion, depreciation & amortization	**$ 4,189**	$ 5,560	**$ 25,649**	$ 32,508
Depletion per sales ($/boe)	**$ 7.80**	$ 12.76	**$ 10.86**	$ 14.02

DD&A expense decreased on an overall basis during the current reporting periods compared to the same periods of 2015. These decreases resulted from lower depletion rates and, for the reported year, lower production volumes. The decreases in our depletion rates for the reported year was due to the impact of lowering the 2016 carrying value of our D&P assets to their recoverable value through recognizing a third quarter of 2015 impairment charge of $75 million. We also are reporting a fourth quarter decrease in the carrying value of the Subject Assets through an impairment charge of $52.0 million reported in the third quarter of 2016.

Our proved plus probable reserves of 26,488 mboe at December 31, 2016, was adjusted for production and then applied in determining the fourth quarter depletion rate for our on-going operations. These reserves decreased during the reported year due to removing the reserves associated with the Subject Assets. However, we increased the proved plus probable reserves for our on-going operations. Our on-going operations' future development costs, which are included in our depletion rate, are $115.1 million at December 31, 2016. We calculated Craft's depletion rate from their proved plus probable reserves and future development costs as determined from an internally prepared reserve report.

Losses (Gains) on Disposition of Properties

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Losses (gains) loss on disposition of properties	**$ 224**	$ (1,544)	**$ (5,796)**	$ (23,331)

During the reported year, we completed the sale of certain petroleum and natural gas properties located in the Gold Creek area of northeastern Alberta and the Enchant area of southcentral Alberta, in addition to Craft's October 2016 disposition of certain Subject Assets, for total proceeds of $21.4 million. The comparative period's gain was from the sale of the Karr and Rainbow properties, both in northwestern Alberta as well as three swap transactions. Aggregate proceeds associated with the comparative period's gain were $42.8 million.

Share-Based Compensation

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Share-based compensation	**$ 558**	$ 599	**$ 2,243**	$ 2,370

Late in the second quarter of 2016, the first tranche of the 2015 restricted and performance awards vested. As a result, the share-based compensation for the current reporting periods modestly decreased compared to the same periods of 2015.

Bad Debt Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Bad debt expense	**$ 177**	$ 518	**$ 635**	$ 1,072

In an effort to manage our credit risk we continuously monitor and assess the collectability of our purchaser and joint arrangement partners' receivables in addition to our other receivable positions. For the current reporting periods, we identified receivables due from joint arrangement partners that had either filed for creditor protection or have since become insolvent. As a result, for the current reporting periods we provided for $0.2 million and $0.6 million of joint partner receivables that were deemed uncollectible.

Foreign Exchange (Gains) Losses & Other

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Foreign exchange (gains) losses & other	**$ (19)**	$ (98)	**$ 617**	$ (639)

During the reported year, we incurred a fee for a take or pay processing agreement in respect of which we did not deliver the required liquids because economic conditions in addition to our strategic alternatives review caused us to delay our Montney development until the fourth quarter. We have partially mitigated our continued exposure to this agreement's costs at least through to the first quarter of 2018. We continue to evaluate other cost mitigation options.

The reported year comparative period includes $0.6 million of foreign exchange gains from our US dollar cash position resulting from the strengthening of the US dollar.

Financing Expenses

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Interest & financing charges (income)	**$ 309**	$ (134)	**$ 802**	$ (243)
Accretion of decommissioning obligation	**374**	611	**2,192**	2,476
Total	**$ 683**	$ 477	**$ 2,994**	$ 2,233

Interest & financing charges increased $0.4 million and $1.0 million during the current reporting periods compared to the same periods of 2015. These increases were caused by less interest income resulting from a decrease in our cash position in addition to interest expense on the Craft acquired debt and the associated financing costs. Borrowings under Craft's credit facility incurred interest at a rate equal to 9% per annum. This debt was included in our measure of the Craft Share Distribution. Chinook does not have outstanding debt as at December 31, 2016.

The accretion charges during the current reported periods decreased compared to the same periods of 2015. These decreases resulted from dispositions of decommissioning obligations and applying a lower average discount rate to account for the passage of time of such obligations. Our future periods' accretion expense will be lower because of the reported year's $69.7 million decreased provision substantially resulting from the Subject Assets through either property dispositions or the Craft Share Distribution.

Income Tax

We have not reported deferred tax assets because it is not probable that we can utilize these assets against future taxable profit. At December 31, 2016, we had the following tax pools:

($ thousands)	December 31 2016
Canadian oil & gas property expense	**$ -**
Canadian development expense	**57,973**
Canadian exploration expense	**54,725**
Undepreciated captial costs	**28,229**
Non-capital losses	**230,430**
Capital losses	**10,750**
Other	**3,762**
Total	**$ 385,869**

Non-Controlling Interest

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Net loss attributable to non-controlling interest	**$ (3,028)**	$ -	**$ (20,625)**	$ -

The net loss of Craft from June 10, 2016 to December 12, 2016, was $68.7 million. This net loss was caused by charges such as impairment, realized loss on sale of the Notes, financing, unrealized losses on price commodity contracts and transaction costs. This resulted in a recovery from the net loss attributable to the 30% non-controlling interest.

Net and Comprehensive Loss

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2016**	2015	**2016**	2015
Weighted average shares outstanding - basic (thousands)	**216,443**	215,337	**215,860**	215,197
Dilutive impact of share based awards (thousands)	**178**	-	**-**	-
Weighted average shares outstanding - diluted (thousands)	**216,621**	215,337	**215,860**	215,197
Net & comprehensive income (loss)	**$ 6,427**	$ (5,303)	**$ (54,773)**	$ (83,606)
Per share - basic & diluted ($/share)	**$ 0.03**	$ (0.02)	**$ (0.25)**	$ (0.39)

We are reporting an increase in net income during the fourth quarter compared to a net loss for the same quarter of 2015. This increase resulted from $0.2 million of higher funds flow and a $17.0 million reversal of prior years' impairment expense caused by higher proved plus probable reserves from our on-going operations held in the Peace River Arch CGU. This reversal excludes a $6.1 million impairment charge to lower Craft's combined D&P and E&E assets, net of decommissioning obligations, to their estimated fair value less costs to sell immediately prior to removing these net assets from our consolidated statements of financial position as a result of the successful completion of the Craft Share Distribution.

For the reported year there was a decrease in the net loss compared to the same period of 2015. This decrease resulted from the reported year's lower impairment expense, net of a reversal, of $41.1 million compared to the higher impairment expense reported during the same period of 2015 for $75.0 million.

Capital Resources, Capital Expenditures and Liquidity

Since the beginning of the economic downturn during 2014 we have focused on capital preservation and optionality while continuing to focus our operation through non-core asset dispositions. With the completion of the Craft Share Distribution during the fourth quarter and dispositions of non-core properties during the reported year, we have completed our transition to a pure play Montney company focused on the development of liquids-rich natural gas production from our Birley/Umbach properties. In disposing of non-core properties we have received capital and freed up operating funds to focus on this core property. In addition, we reduced our future provisions by $69.7 million. We have also completed two separate transactions to dispose of non-core assets for $18.0 million during the first quarter of 2017 with associated production volumes of 100 boe/d. With these additional funds in addition to our $15.1 million net surplus as at December 31, 2016, we have the necessary financing to fund our $40 million capital program during 2017. However, this capital program is scalable and may be reduced by us if required to meet changing economic conditions.

During the first quarter of 2017, we executed an $8.0 million demand credit facility with a Canadian chartered bank. Borrowings under this credit facility will be limited to $2 million subject to confirmation that the three wells from our fourth quarter drilling program at Birley/Umbach are producing to the lender's satisfaction. Although we do not anticipate drawing on this facility during 2017, fund availability from this facility provides us with further financial flexibility.

For the reported year, we financed expenditures for development and exploration, decommissioning in addition to an increase in non-cash working capital from cash on hand and proceeds from property dispositions. Craft financed its debt repayments from a property disposition and funds flow.

Funds (Outflow) from Operations

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2016**	2015	**2016**	2015
Cash (outflow) flow from operating activities	**$ (1,517)**	$ (868)	**$ (9,320)**	$ 3,381
Add back (deduct):				
Change in operating non-cash working capital	**1,933**	(334)	**511**	116
Decommissioning obligation expenditures & other	**114**	1,987	**3,914**	3,888
Exploration & evaluation expenses	**(239)**	731	**729**	1,648
Transaction & distribution costs	**1,422**	-	**3,162**	-
Funds (outflow) from operations [1]	**$ 1,713**	$ 1,516	**$ (1,004)**	$ 9,033
Per share - basic & diluted	**$ 0.01**	$ 0.01	**$ -**	$ 0.04

(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 fourth quarter's funds from operations increased to $1.7 million from $1.5 million in the same quarter of 2015 as a result of increases in both production volumes and corporate netbacks.

During the reported year we are reporting an outflow from operations of $1.0 million compared to funds from operations of $9.0 million in the same period of 2015. Lower production volumes and corporate netbacks resulted in lower funds from operations. This lower corporate netback was due to lower realized average commodity pricing. Also contributing to the decrease was lower realized commodity price contract gains, a realized loss on the Notes, interest charges associated with Craft's outstanding debt and a fee resulting from a take or pay processing agreement.

Credit Facilities

	December 31 2016	December 31 2015
($ thousands)		
Long-term debt	**$ -**	$ -
Add:		
Accounts payable, accrued liabilities & other	**11,218**	21,607
Less:		
Cash and restricted cash	**(16,129)**	(37,947)
Accounts receivable	**(6,658)**	(11,173)
Prepaids & deposits	**(3,569)**	(2,101)
Net surplus [1]	**$ (15,138)**	$ (29,614)

(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 a net surplus of $15.1 million at December 31, 2016 compared to $29.6 million at December 31, 2015. This decrease of $14.5 million excludes the effects of Craft's operations, financing and investing activities, and was caused by a funds outflow from operations and capital, decommissioning, exploration and evaluation expenditures, net of disposition proceeds, transaction and distribution costs and our initial cash investment on the acquisition of Craft.

During the reported year, we voluntarily reduced our reserve-based credit facility (the "Previous Credit Facility"), with a Canadian bank, from $50.0 million to $nil, as a result of the transfer of the Subject Assets to Craft. There were no outstanding draws at the time of this voluntary reduction in the borrowing base (undrawn with a borrowing base of $50.0 million - December 31, 2015). The Previous Credit Facility did not include any financial covenants or reporting requirements and was collateralized by floating charges and security interests over all of our present and future properties and other assets.

Subsequent to December 31, 2016, the Previous Credit Facility agreement was terminated and we executed an $8.0 million demand credit facility (the "Demand Credit Facility") with a Canadian chartered bank. Borrowings under the Demand Credit Facility will be limited to $2 million subject to confirmation that the three wells from our fourth quarter drilling program at Birley/Umbach are producing to the lender's satisfaction. At any time, the lender can request repayment of all outstanding drawn amounts resulting in any future borrowings being classified as a currently liability. The Demand Credit Facility's availability is subject to annual reviews with the first review scheduled for June 1, 2017. Changes in the availability in the Demand Credit Facility are possible, from one review to the next, with draws in excess of availability becoming immediately payable. Borrowings will 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. The Demand Credit Facility has a financial covenant requiring that the adjusted working capital be 1:1 at each reporting period. For purposes of this covenant, adjusted working capital is defined as working capital excluding both current commodity price contracts and debt. In addition, the Demand Credit Facility includes operating and financial restrictions on us that include restrictions on paying dividends or repurchasing or making other distributions with respect to our securities.

The terms of the Demand Credit Facility also require that we must enter into commodity price contracts covering no less than 30% of our forecasted twelve month combined production volumes of crude oil, natural gas and natural gas liquids.

Capital Expenditures

Our capital expenditures were as follows:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2016**	2015	**2016**	2015
Land & lease	**$ 15**	$ 550	**$ 164**	$ 1,136
Drilling & completions	**3,951**	142	**3,951**	17,595
Facilities & equipment	**-**	8,904	**4,083**	24,176
Field expenditures	**3,966**	9,596	**8,198**	42,907
Capitalized G&A	**211**	395	**1,013**	1,351
Furniture & equipment	**-**	7	**-**	67
Total	**$ 4,177**	$ 9,998	**$ 9,211**	$ 44,325

During the fourth quarter we successfully drilled three wells (2.63 net) at Birley/Umbach. The drilling of these wells was completed on schedule and under budget by approximately 26% with average drilling costs of approximately $1.28 million per well ($1.12 million, net). We completed and tied-in these three wells during the first quarter of 2017.

Rationalization of Non-Core Properties

We may, from time to time, dispose of non-core properties so that we can focus on the development of Montney liquids-rich natural gas at Birley/Umbach. We further transformed into a pure play Montney liquids-rich natural gas company upon completion of the Craft Share Distribution. During October 2016, Craft completed the disposition of certain assets in Alberta, including certain of the Subject Assets, for proceeds of $13.5 million, before customary adjustments. These disposed properties are located in central and southern Alberta and were prospective for Cardium light oil and natural gas in the Willesden Green and Ferrier areas, among others. In addition, during the reported year we also completed the sale of petroleum and natural gas properties located in the Enchant area of southcentral Alberta and the Gold Creek area of northeastern Alberta, for net proceeds of $8.2 million. During the first quarter of 2017, we completed the disposition of certain non-core assets located at East Gold Creek and Knopcik/Pipestone for net consideration of approximately $18.0 million, subject to closing adjustments. These dispositions resulted in Assets and Liabilities Held for Sale at December 31, 2016.

Provisions

The December 31, 2016 provisions relates to the future abandonment and reclamation of our properties. At December 31, 2016, we had provisions of $29.1 million, which was a decrease from $98.7 million at December 31, 2015. We estimate the net present value of the total decommissioning obligation based on a total future undiscounted and uninflated liability of $31.2 million (December 31, 2015 - $99.5 million).

A decrease in the provision of $83.5 million resulted from the removal of both the Subject Assets and other property dispositions associated decommissioning obligations and the transfer to liabilities held for sale. Further decreasing our provision was decommissioning obligations and other expenditures of $3.9 million. Partially offsetting these decreases was a $4.0 million fair value estimate of decommissioning obligations acquired from Craft immediately followed by an increase of $15.1 million to the change in estimate for these same obligations caused by applying risk-free discount rates from those rates used to measure fair value. These increases to the additions and change in estimate were partially offset by an increase in the risk free rate causing a decrease to the provision by $3.5 million. As a result, the net increase to the additions and change in estimate is $11.6 million. The recognized accretion charges reflect the increase in the obligation associated with the passage of time.

As at December 31, 2016 and 2015, the estimated obligation includes 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, as well as annual inflation of 2.0%, in order to calculate the future obligation. At December 31, 2016 and 2015, a risk-free interest rate of 2.34% and 2.16%, respectively, was used in order to calculate the present value of the obligation.

Outstanding Share Data

Authorized:

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

Details of share capital and share awards outstanding are as follows:

	December 31 2016	December 31 2015
Common shares outstanding	**216,442,834**	215,349,412
Share options	**6,471,200**	9,465,617
Restricted awards	**349,241**	1,084,226
Performance awards	**381,790**	1,006,996
Weighted average common shares - basic and diluted	**215,860,123**	215,196,938

As at March 22, 2017, we had 216,442,834 common shares, 5,935,700 share options, 336,423 restricted awards and 360,255 performance awards outstanding.

Commitments and Guarantee

At December 31, 2016, 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)	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Office leases	$ 2,416	$ 2,416	$ 1,208	$ -	$ -	$ -	$ 6,040
Operating & transportation contracts	6,867	6,672	4,771	2,975	208	-	21,493
	$ 9,283	**$ 9,088**	**$ 5,979**	**$ 2,975**	**$ 208**	**$ -**	**$ 27,533**

Office lease commitments relate to our head office in Calgary, Alberta. Operating and transportation contracts relate to minimal contractual payments if we do not utilize firm pipeline capacity.

As a result of the voluntary reduction in the Previous Credit Facility's borrowing base to $nil, we were required to secure a total of $1.3 million in outstanding letters of credit through depositing an equivalent amount in cash with our lender.

We are involved in litigation and claims arising in the normal course of operations and from indemnifications provided to the buyer of our former Tunisian operations in 2014. At December 31, 2016, claims from a former Tunisian service provider and the Tunisian Tax Authority totaled $15 million. Our subsidiary, Storm Ventures International (BVI) Limited, provided the buyer indemnifications for claims of this nature which are guaranteed by us. As of December 31, 2016 and 2015, an estimate of possible future disbursements for these indemnifications, including professional costs, totaled $1.2 million and is recorded in accounts payable, accrued liabilities and other on the consolidated statements of financial position. There have been no payments for such claims during the year ended December 31, 2016. During the year ended December 31, 2015, we paid $1.9 million of such costs as reported on the consolidated statements of cash flow as a change in investing activities from discontinued operations. While the outcome of the remaining claims in excess of $1.2 million is not known with certainty, management is of the view that such claims are without merit and will represent our interests vigorously in any future legal or arbitration proceedings. See "Risk Factors".

Off Balance Sheet Arrangements

We did not enter into any off balance sheet arrangements during the current reporting 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 included in general and administrative expenses for the reported and comparable years totaled $2.3 million and $2.6 million, respectively. Long-term incentive benefits for our officers and directors as included in share-based compensation for the reported and comparable years totaled $1.2 million and $1.3 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 37.1% 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 between 1542991 Alberta Ltd. ("WOGH GP") and our company, WOGH GP engaged our company to perform its duties under the partnership agreement and to manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership in connection with the partnership business and to make all decisions relating thereto. WOGH Limited Partnership 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 Limited Partnership, we are reimbursed for such services. In accordance with the Services Agreement, we reported a recovery from WOGH Limited Partnership, as reported against our G&A expense, of $1.4 million and $1.7 million for the reported and comparable years. The recovery for the reported and comparative years was generally determined from WOGH Limited Partnership's pro rata share as estimated at 14% of its and CEI's combined production volumes. At December 31, 2016, $0.1 million of this G&A recovery was included in accounts receivable (December 31, 2015 - $0.2 million). .

One of our directors owns a significant shareholding in Alliance Trust Company, which is our registrar and transfer agent. Fees charged by Alliance Trust Company to us totaled $0.1 million in each of the reported year and comparative period.

Outlook

On January 23, 2017, we announced a $40 million capital program for 2017 which included the expansion of our facility at Birley/Umbach to 50 mmcf/d and the drilling of six (4.5 net) wells which were anticipated to be 1,600 meters in length with frac spacing of 60 to 65 meters. We are optimizing our drilling and completion program which has been revised to now include the drilling of four (3.67 net) wells, two (2.0 net) of which will have lateral sections of 1,600 meters in length and two (1.67 net) will have 1,800 meter length laterals. All four wells will have tighter frac spacing of approximately 52 meters from the original 60 to 65 meters. The additional length of two of the wells is anticipated to add to the recoverability of hydrocarbons while increased frac density is anticipated to result in increased initial well rates. This change in our drilling program will result in 10% more net frac stages despite resulting in 0.83 fewer net wells. As a result of the longer length of two of the wells and the decreased frac spacing, the amount of our capital program will be maintained at $40 million. We are also marginally increasing our previously announced average and ending production for 2017 and marginally decreasing our working capital surplus at December 31, 2017 as follows:

($ millions, except boe/d)	Original 2017 Guidance (1)	**Revised 2017 Guidance (2)**
Average production (boe/d)	4,070 - 4,170	4,200 - 4,300
Exit production (boe/d)	6,000 - 6,150	6,300 - 6,500
Capital expenditures	$ 40	$ 40
Net surplus as at December 31, 2017	$ 3	$ 2

(1) Original 2017 guidance assumptions: AECO natural gas price $2.93/mmbtu, Station 2 natural gas price $2.26/mmbtu and Chicago Alliance natural gas price $3.20/mmbtu.
(2) Revised 2017 guidance assumptions: AECO natural gas price $2.64/mmbtu, Station 2 natural gas price $2.11/mmbtu and Chicago Alliance natural gas price $2.92/mmbtu.

	Original 2017 Guidance		**Revised 2017 Guidance**	
	Gross	Net	**Gross**	**Net**
Drilling program (wells)	6	4.5	**4**	**3.67**
Frac stages for drilling program	144	107.4	**130**	**118.4**

Selected Annual Information

Summarized information by year for the three years ended December 31, 2016, appears below:

Year ended December 31	**2016**	**2015**	**2014**
($ thousands, except per share amounts)			
Petroleum & natural gas revenue, net of royalties from Continuing Canadian Operations (1)	**$ 36,943**	$ 49,701	$ 118,662
Net loss from Continuing Canadian Operations (1) (2)	**$ (54,773)**	$ (83,606)	$ (50,672)
Per share - basic & diluted ($/share)	**$ (0.25)**	$ (0.39)	$ (0.24)
Net loss (2) (3)	**$ (54,773)**	$ (83,606)	$ (38,400)
Per share - basic & diluted ($/share)	**$ (0.25)**	$ (0.39)	$ (0.18)
Total assets	**$ 139,975**	$ 321,564	$ 434,318
Long-term financial liabilities (4)	**$ 27,767**	$ 96,042	$ 106,726

(1) For the year ended December 31, 2014, results do not include those from our former Tunisian operations which were sold on August 19, 2014.
(2) Includes $41.1 million, $75 million and $63.5 million of net impairment charges for the year ended December 31, 2016, 2015 and 2014, respectively.
(3) For the year ended December 31, 2014, net income includes results from our former Tunisian operations which were sold on August 19, 2014.
(4) Includes loans and borrowings, provisions and other long-term liabilities.

Factors That Have Caused Variations over the Years

During the reported year and 2015, significant decreases in commodity prices and lower production due primarily to the voluntary shut-in of production in response to low commodity prices and to the disposition of properties in Karr, Rainbow and Gilby, Enchant, Gold Creek, in addition to the removal of the Subject Assets, resulted in significant decreases in our petroleum and natural gas revenues, net of royalties.

Our net losses for the years ended 2014 and 2015 were negatively impacted by impairment charges resulting from decreases in forward commodity pricing. For the reported year the impairment charge related to the Subject Assets held by Craft. These impairment charges, in addition to our non-core property dispositions, were greater than our capital expenditures and property acquisitions resulting in a decrease in the carrying value of our total assets in each consecutive year. The decreases in long-term financial liabilities resulted from lower decommissioning obligations also caused through property dispositions. Please refer to “Operations” and other sections of this MD&A for detailed discussions on variations during the comparative year ended and to our previous annual management’s discussion and analysis for changes in the prior years.

Quarterly Information from Operations

Summarized information by quarter for the two years ended December 31, 2016, appears below:

	Dec. 31 2016	Sept. 30 2016	Jun. 30 2016	Mar. 31 2016	Dec. 31 2015	Sept. 30 2015	Jun. 30 2015	Mar. 31 2015
Production Volumes								
Crude oil (bbl/d)	**451**	1,036	769	817	922	1,065	1,284	1,485
Natural gas liquids (boe/d)	**613**	599	604	733	364	395	604	682
Natural gas (mcf/d)	**21,548**	28,972	22,776	25,215	15,851	20,641	25,290	33,007
Average daily production (boe/d)	**4,655**	6,464	5,169	5,753	3,928	4,900	6,103	7,668
Sales Prices								
Average oil price ($/bbl)	**$ 71.98**	$ 57.31	$ 50.59	$ 35.41	$ 47.93	$ 51.34	$ 62.90	$ 49.03
Average natural gas liquids price ($/boe)	**$ 40.70**	$ 10.67	$ 25.78	$ 27.65	$ 30.59	$ 31.68	$ 41.06	$ 36.47
Average natural gas price ($/mcf)	**$ 3.31**	$ 2.22	$ 1.35	$ 1.43	$ 2.09	$ 2.56	$ 2.50	$ 2.65
Netback (1)								
Average commodity pricing ($/boe)	**$ 27.67**	$ 20.14	$ 16.50	$ 14.82	$ 22.51	$ 24.48	$ 27.67	$ 24.15
Royalties ($/boe)	**$ (2.84)**	$ (0.77)	$ (0.44)	$ (0.99)	$ 2.39	$ (1.13)	$ (0.78)	$ (2.07)
Net production expenses ($/boe) (1)	**$ (11.88)**	$ (12.61)	$ (14.75)	$ (15.12)	$ (14.17)	$ (12.49)	$ (18.36)	$ (17.04)
G&A expense ($/boe)	**$ (5.80)**	$ (4.70)	$ (4.40)	$ (3.61)	$ (8.31)	$ (4.39)	$ (3.70)	$ (4.00)
Netback ($/boe) (1)	**$ 7.15**	$ 2.06	$ (3.09)	$ (4.90)	$ 2.42	$ 6.47	$ 4.83	$ 1.04
Wells Drilled (net)								
Total natural gas wells drilled (net)	**2.63**	-	-	-	-	-	-	2.75
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties	**$ 10,631**	$ 11,518	$ 7,550	$ 7,244	$ 9,000	$ 10,527	$ 14,934	$ 15,240
Funds (outflow) from operations (1)	**$ 1,713**	$ 1,894	$ (1,721)	$ (2,890)	$ 1,516	$ 3,299	$ 2,995	$ 1,220
Per share - basic & diluted ($/share)	**$ 0.01**	$ 0.01	$ (0.01)	$ (0.01)	$ 0.01	$ 0.02	$ 0.01	$ 0.01
Net (loss) income (2)	**$ 6,427**	$ (35,905)	$ (12,520)	$ (12,775)	$ (5,303)	$ (80,669)	$ (5,822)	$ 8,189
Per share - basic & diluted ($/share)	**$ 0.03**	$ (0.17)	$ (0.06)	$ (0.06)	$ (0.02)	$ (0.37)	$ (0.03)	$ 0.04
Capital expenditures	**$ 4,177**	$ 661	$ 1,347	$ 3,026	$ 9,998	$ 7,313	$ 4,921	$ 22,093
Net surplus (1)	**$ (15,138)**	$ (7,217)	$ (6,207)	$ (20,180)	$ (29,614)	$ (41,181)	$ (46,705)	$ (48,596)
Total assets	**$ 139,975**	$ 274,674	$ 366,586	$ 299,623	$ 321,564	$ 333,036	$ 414,280	$ 431,085
Common Shares (thousands)								
Weighted average during period - basic	**216,443**	216,287	215,350	215,349	215,337	215,274	215,089	215,083
Weighted average during period - diluted	**216,621**	216,287	215,350	215,349	215,337	215,274	215,089	215,112
Outstanding at period end	**216,443**	216,443	215,350	215,350	215,349	215,328	215,236	215,083

(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) Includes ($10.9 million), $52.0 million and $75.0 million in net impairment (reversal) charges against properties for the three months ended December 31, 2016, September 30, 2016 and September 30, 2015, respectively.

Factors That Have Caused Variations over the Quarters

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

Generally, our shut-in of properties in response to lower commodity prices has resulted in a lower trend of natural gas and natural gas liquids production volumes. This trend was offset during the first quarter of 2016 when we brought on-stream an additional three (2.75 net) wells from our 2015 drilling program at Birley/Umbach on the commissioning of our new compression facility. Our crude oil production volumes generally trended down due to ongoing pipeline service restrictions and reduced system capacity and decreased significantly during the fourth quarter as a result of the removal of the Subject Assets in addition to other non-core property dispositions.

Our realized commodity prices and petroleum and natural gas revenue, net of royalties have mostly trended with the Canadian Light Sweet and AECO benchmarks which decreased throughout 2015 with the Canadian Light Sweet benchmark not beginning to recover until the second quarter of 2016 while the AECO benchmark did not begin to substantially recover until the third quarter of 2016. Changes in our petroleum and natural gas revenues, net of royalties and funds from operations have generally trended with benchmark commodity prices and volumes. Starting during the first quarter of 2015 our net surplus began to decrease as our capital expenditures exceeded our funds from operations. It further decreased in the second quarter of 2016 when we acquired debt from the Craft acquisition until December 12, 2016, when we completed the Craft Share Distribution. Our capital preservation efforts resulted in no drilling activity from the first quarter of 2015 until the fourth quarter when we completed a three (2.63 net) well drilling program at Birley/Umbach. Our dispositions of non-core assets combined with funds from operations relative to capital expenditures have allowed us to avoid having to raise proceeds through the issuance of our common shares.

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

Risk Factors

Investors should carefully consider the risk factors set out in our Annual Information Form for the year ended December 31, 2016 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 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".

Exploration, Development and Production Risks

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

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, 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 our business, financial condition, results of operations and prospects.

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we could incur significant costs.

Weakness in the Oil and Natural Gas Industry

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 emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional downward price pressure on oil and gas produced in western Canada and uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the borrowing base under our credit facilities, which, depending on the level of our indebtedness, could result in us having to repay a portion of our indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance our reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and 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 us.

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 our control. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, 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 our ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of our 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 our reserves. We might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our 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 our carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our 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, 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.

Our product profile comprises a large and growing percentage of natural gas. Pricing and access to markets has been affected by the growth of domestic gas production in the United States. When, if ever, access to historical markets in the United States may improve, is not predictable. Further, development of certain natural gas reserves in Canada is to a degree underwritten by the expectation that new Pacific Rim export markets will be accessed through the establishment of LNG liquefaction facilities on Canada's west coast. When such facilities will be completed, if ever, cannot be predicted.

Gathering and Processing Facilities and Pipeline Systems

We deliver our products through gathering and processing facilities and pipeline systems some of which we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of availability of capacity in any of the gathering and processing facilities and pipeline systems, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit 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 our production, operations and financial results. As a result, producers are increasingly turning to rail 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 our business and, in turn, our financial condition, results of operations and cash flows. In addition, the federal government has signaled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do 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 material adverse effect on our ability to process our production and deliver the same for sale.

During 2016, the majority of our natural gas production in northeast British Columbia was subject to the AECO – BC Station 2 differential which was -$0.41 per GJ and fluctuated between -$1.61 per GJ and +$0.50 per GJ from 2010 to 2015. Going forward, exposure to the AECO – BC Station 2 differential is reduced as a result of our contracting capacity on the Alliance Pipeline effective May 1, 2016 for delivery of natural gas to the Chicago area.

We have contracted pipeline transportation capacity for approximately 20% of total forecasted natural gas sales volumes in 2017 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

We are subject to risks relating to certain obligations guaranteed in favour of the buyer in connection with the disposition of our Tunisian operations which was completed on August 19, 2014. We have guaranteed the payment of the indemnification obligations of Storm Ventures International (BVI) Limited ("**Storm BVI**"), a wholly-owned subsidiary of us, 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 us to the buyer, which in turn could have a material adverse effect on our working capital and financial condition. A copy of the share purchase and sale agreement is available on our SEDAR profile.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our common shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our common shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets may realize less on disposition than their carrying value on our financial statements.

Political Uncertainty

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. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States 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 gas companies, including us.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. 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 our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our common shares.

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, we potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on our financial and operational results.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget, or at all and may be unable to market the oil and natural gas that we produce effectively.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than us. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than us. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If we do implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be affected adversely and materially. If we are unable to utilize the most advanced commercially available technology, or are unsuccessful in implementing certain technologies, our business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. 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 our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act (Canada)* and the *Investment Canada Act* could negatively affect our business, financial condition and the market value of our common shares or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our 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

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 our 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 we are ultimately able to produce from our reserves.

Environmental

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 certain oil and 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 us to incur costs to remedy such discharge. Although we believe that we 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 our business, financial condition, results of operations and prospects.

Liability Management

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 obligation. These programs generally 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 required. Changes to the required ratio of our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to our compliance requirement. In addition, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and 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 recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the Alberta Energy Regulator’s abandonment and reclamation powers when the licensee is insolvent. The Alberta Energy Regulator appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas ("**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 *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the *Climate Leadership* Act ("**CLA**") come into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, 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. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of our reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results.

To the extent that we engage in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which we may contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of our common shares.

Substantial Capital Requirements

We anticipate 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, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- Our 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 our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. 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 us. We may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing.

As a result of global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

The Demand Credit Facility is available at the discretion of the lender and may be demanded at any time. The amount authorized under the Demand Credit Facility is dependent on the borrowing base determined by the lender from time to time. Notwithstanding the discretionary and demand nature of the Demand Credit Facility, we are required to comply with covenants under the Demand 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 Demand Credit Facility. In the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to the failure of us to comply with these covenants. A failure to comply with the applicable covenants (including the financial ratio tests) could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under the Demand Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Demand Credit Facility may impose operating and financial restrictions on us that could include restrictions on paying dividends or repurchasing or making of other distributions with respect to our 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.

Our lender uses our reserves, commodity prices, applicable discount rates and other factors, to periodically determine our borrowing base. As a result of the depressed commodity prices experienced in the last two years, our borrowing base was reduced in December 2016. 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 our borrowing base, reducing the funds available to us under the Demand Credit Facility. This could result in the requirement to repay a portion, or all, of our indebtedness.

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

Issuance of Debt

From time to time, we 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 our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we 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, our hedging arrangements may expose us 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 we 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, we will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to us and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. Our actual interest in properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue received by us.

Reserve Estimates

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. Our actual production, revenues, taxes and development and operating expenditures with respect to our 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. Such variations could be material.

In accordance with applicable securities laws, our 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 our 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 we intend 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 our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain 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, we 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 us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Control by Principal Shareholder

Her Majesty the Queen in Right of the Province of Alberta ("**HMQ**") owns 80,357,142 common shares, representing approximately 37% of our 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 our business and affairs 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 us, including transactions in which our minority shareholders 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 us 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 us.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of our net production revenue.

In addition, our oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities which may be dilutive.

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

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

Dividends

We have not paid any dividends on our outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of us, the need for funds to finance ongoing operations and other considerations, as our Board of Directors considers relevant. The Demand Credit Facility prohibits us from paying dividends on our common shares.

Litigation

In the normal course of our operations, we 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, relating 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 us, and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail 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 our financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on our business and financial results.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act (Canada)* and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Seasonality

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. 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 swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In addition, we may be exposed to third party credit risk from operators of properties in which we have a working or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find 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 us being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

Certain of our directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the *Business Corporations Act (Alberta)* which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act (Alberta*).

Reliance on Key Personnel

Our 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 our business, financial condition, results of operations and prospects. We do not have any key personnel insurance in effect. The contributions of the existing management team to our immediate and near term operations 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Information Technology Systems and Cyber-Security

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

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our 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 our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. 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 our business, financial condition and results of operations.

Expansion into New Activities

The operations and expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial condition being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on our 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.

Additional information on the risks, assumptions and uncertainties are found under the heading " Forward-Looking Statements" of this MD&A.

Management Judgment and Estimation Uncertainty

The preparation of the Financial Statements requires 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 obligation

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, substantively enacted tax rates and the likelihood of assets being realized from future taxable earnings.

New Accounting Standards Not Yet Adopted

In July 2014, the IASB issued IFRS 9 "Financial Instruments" to replace IAS 39, "Financial Instruments Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial instruments with a single model that has only two classifications categories: amortized cost and fair value. We are currently assessing the impact of this standard.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to replace International Accounting Standard ('IAS") 18, Revenue, IAS 11 "Construction Contracts", and related interpretations. The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which affect the amount and/or timing of revenue recognized. We are currently assessing the impact of this standard.

As of January 1, 2018, we will be required to adopt the above two standards.

In January 2016, the IASB issued IFRS 16 “Leases”. The standard requires entities to recognize lease assets and lease obligations on the statement 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 (“ROU”) asset and a lease liability, and the lease will be treated as an asset on a financed basis. There will be an optional exemption from the above for short term leases and leases of low value assets, defined at 12 months or less and 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 are currently assessing all major leases including firm commitment contracts, which are expensed as operating leases for reclassification to the statement of financial position.

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, 2016 and have concluded that our disclosure controls and procedures are effective at December 31, 2016.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting 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 internal controls over financial reporting at December 31, 2016 and have concluded that our internal controls over financial reporting are effective at December 31, 2016.

We have designed our internal controls over financial reporting 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 described below 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.

- Funds (outflow) from operations is calculated from cash flow from operations adjusted for changes in non-cash working capital related to operations, exploration and evaluation expenses related to operations, decommissioning obligation expenditures related to operations and transaction costs. We believe that funds (outflow) from operations is a key measure to assess our ability to finance capital expenditures and when debt is drawn, debt repayments. Funds (outflow) from operations is not intended to represent cash flow from operating activities, net earnings 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. We adjust exploration and evaluation expense as we could otherwise capitalize these expenses.

- Net debt (surplus) is calculated as bank debt adjusted for current assets less current liabilities as they appear on the balance sheets, both of which exclude mark-to-market derivative contracts and assets and liabilities held for sale and current liabilities excludes any current portion of debt and decommissioning obligation. We use net debt (surplus) to assist us in understanding our liquidity at specific points in time. We exclude the current portion of decommissioning obligation as it is not a financial instrument and only once it has been incurred and in turn cycled through accounts payable, accrued liabilities or a reduction in cash, do we view it as an adjustment to our net debt (surplus). Mark-to-market derivative contracts are excluded as they are unrealized.

- Netback is calculated as a period's sales of petroleum and natural gas, net of royalties less net production and operating expenses and G&A expense, divided by the period's sales volumes. We use this non-GAAP measure to assist us in understanding our profitability relative to current commodity prices and it provides an analytical tool to benchmark changes in 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. We include G&A expense in our Netback calculation as it represents the administrative component of developing the associated production.

- Operational netback is calculated as a period's sales of petroleum and natural gas, net of royalties less net production expenses, divided by the period's sales volumes. We use this non-GAAP measure to assist us in understanding our field profitability relative to current commodity prices and it provides an analytical tool to benchmark changes in field operational performance against prior periods.

- Net production and operating expense is calculated as production and operating expense less processing and gathering revenues. We use net production and operating expense to determine the current periods' cash cost of operating expenses and net production and operating expense per boe is used to measure operating efficiency on a comparative basis.

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: our expectation that the new gas handling agreement will significantly improve our go-forward drilling economics and reduce our operating costs, future G&A cost reductions and the realization thereof, our expected future production costs, plans and operations including our intention to concentrate on our Montney assets, the amount and composition of our 2017 capital program and how we intend to fund the program, future exploration and development activities and the timing thereof and how we intend to manage our company as our revised guidance regarding average and ending production for 2017, capital expenditures for 2017 and working capital surplus at December 31, 2017 set forth under the heading "Outlook". In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

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, 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 2017 capital program, 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, 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 2017 capital program 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.

Reserves

The recovery and reserves estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

Future Oriented Financial Information

This MD&A, in particular the information in respect of our anticipated capital expenditures in 2017 and our guidance in respect of our working capital surplus at December 31, 2017, 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
mmbtu	million British Thermal units
GJ	gigajoule
GJs	gigajoules
GJs/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
AECO	Central market point for Canadian natural gas
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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.

Initial Production Rates

Any reference in this MD&A to initial, early and/or test or production/performance rates (including IP30, IP60 and IP90) are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating our aggregate production. The initial production or test rates may be estimated based on other third party estimates or limited data available at this time. In all cases in this news release initial production or test rates are not necessarily indicative of long-term performance of the relevant well or fields or of ultimate recovery of hydrocarbons. Well-flow test result data should be considered to be preliminary until a pressure transient analysis and/or well-test interpretation has been carried out.