# 2015 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. ("our", "we" or "us") for the years ended December 31, 2015 and 2014 and should be read in conjunction with our consolidated financial statements and accompanying notes as at and for the years ended December 31, 2015 and 2014 (the "Financial Statements"). This MD&A is based on information available as at March 7, 2016.

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, 2015, 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, 2015, in this respective order. The term "same period(s) of 2014" and "comparative period(s)" or similar terms are used throughout this document and refer to the three months or (and) year ended December 31, 2014, in this respective order, depending on the 2015 period(s) under discussion.

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

## Additional Information

Additional information on our company can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com. Our Annual Information Form for the year ended December 31, 2015 ("AIF") will be filed on SEDAR prior to March 31, 2016.

## Basis of Presentation

Our Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Our consolidated financial position (the "Balance Sheet") and results of operations include the accounts of our direct subsidiaries all of which are wholly owned. As discussed in the "Discontinued Operations" section of this MD&A, the comparative year's results of operations also include the accounts of our discontinued operations as presented on the line item net income from discontinued operations, net of income taxes. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per unit amounts or as otherwise noted. Certain financial measures referred to in this MD&A, such as funds from operations (and per share), netback, net debt (surplus) and net production expense, etc., are not prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

## Introduction to Chinook

We are a Calgary-based public petroleum and natural gas production company focused on development and exploration opportunities in western Canada. Our operations combine multi-zone conventional production and resource plays in our Western Canadian Sedimentary Basin producing properties and undeveloped land predominantly located in northwestern Alberta and northeastern British Columbia ("BC"). We are currently focused on the development of Montney liquids rich natural gas on our Birley/Umbach, BC properties, and are well positioned to return focus to our Montney and Dunvegan light crude oil in Grande Prairie, Alberta. With a modest improvement in commodity prices, these assets provide the opportunity for substantial growth and long-term profitable development.

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.

# Discontinued Operations

On August 19, 2014, our wholly-owned subsidiary, Storm Ventures International (BVI) Limited (“Storm BVI”), completed the sale of all of the issued and outstanding shares of its wholly-owned subsidiary Storm Ventures International (Barbados) Limited (“SVI Barbados”). SVI Barbados’ wholly-owned subsidiary was Storm Sahara Limited (“SSL”). Combined, SVI Barbados and SSL held both of Chinook’s Tunisian operating branches (the “Discontinued Operations”). This disposition represented our complete exit from Tunisian crude oil and natural gas development and exploration. As a result, the associated results of operations for the comparative periods have been presented as Discontinued Operations in this MD&A and the Financial Statements.

# Continuing Operations

Our western Canadian petroleum and natural gas producing and exploration assets, (the “Continuing Canadian Operations”) are discussed in the “Continuing Canadian Operations” section of this MD&A. Unless specifically noted, the current and comparative reporting periods’ operating and financial disclosures and discussions throughout this MD&A are in reference to our Continuing Canadian Operations.

# Financial and Operating Highlights

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| **CONTINUING CANADIAN OPERATIONS** (1) (2) | | | | |
| **Production** | | | | |
| Crude oil (bbl/d) | **922** | 1,981 | **1,187** | 2,038 |
| Natural gas liquids (boe/d) | **364** | 778 | **510** | 779 |
| Natural gas (mcf/d) | **15,851** | 34,879 | **23,642** | 30,721 |
| Average daily production (boe/d) | **3,928** | 8,572 | **5,637** | 7,937 |
| **Sales Prices** | | | | |
| Average oil price ($/bbl) | **$ 47.93** | $ 70.84 | **$ 53.08** | $ 90.68 |
| Average natural gas liquids price ($/boe) | **$ 30.59** | $ 48.05 | **$ 35.83** | $ 65.02 |
| Average natural gas price ($/mcf) | **$ 2.09** | $ 3.57 | **$ 2.50** | $ 4.59 |
| **Netback** (3) | | | | |
| Average commodity pricing ($/boe) | **$ 22.51** | $ 35.26 | **$ 24.89** | $ 47.44 |
| Royalties ($/boe) | **$ 2.39** | $ (4.74) | **$ (0.73)** | $ (6.48) |
| Net production expenses ($/boe) (3) | **$ (14.17)** | $ (18.89) | **$ (15.92)** | $ (17.61) |
| G&A expense ($/boe) | **$ (8.31)** | $ (4.26) | **$ (4.76)** | $ (4.83) |
| Netback ($/boe) (3) | **$ 2.42** | $ 7.37 | **$ 3.48** | $ 18.52 |
| **Wells Drilled (net)** | | | | |
| Oil | **-** | 1.62 | **-** | 6.14 |
| Gas | **-** | 0.83 | **2.75** | 2.70 |
| Disposal/injection | **-** | - | **-** | 0.37 |
| Total wells drilled (net) | **-** | 2.45 | **2.75** | 9.21 |
| **FINANCIAL** ($ thousands, except per share amounts) | | | | |
| Petroleum & natural gas revenues, net of royalties | **$ 9,000** | $ 24,065 | **$ 49,701** | $ 118,662 |
| Funds from operations (3) | **$ 1,516** | $ 6,069 | **$ 9,033** | $ 48,158 |
| Per share - basic & diluted ($/share) | **$ 0.01** | $ 0.03 | **$ 0.04** | $ 0.22 |
| Net loss from continuing operations | **$ (5,303)** | $ (58,311) | **$ (83,606)** | $ (50,672) |
| Per share - basic & diluted ($/share) | **$ (0.02)** | $ (0.27) | **$ (0.39)** | $ (0.24) |
| Capital expenditures | **$ 9,998** | $ 39,671 | **$ 44,325** | $ 96,584 |
| Net debt (surplus) (3) | **$ (29,614)** | $ (28,788) | **$ (29,614)** | $ (28,788) |
| Total assets | **$ 321,564** | $ 434,318 | **$ 321,564** | $ 434,318 |
| **Common Shares** (thousands) | | | | |
| Weighted average during period - basic & diluted | **215,337** | 215,081 | **215,197** | 214,601 |
| Outstanding at period end | **215,349** | 215,082 | **215,349** | 215,082 |

(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. With respect to our Continuing Canadian Operations, production volumes and sales volumes are equal and are used interchangeably throughout this MD&A.

(2) See the "Continuing Canadian Operations" section of this MD&A.

(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.

# 2015 Annual Guidance and Financial Highlights

A summary of our revised 2015 guidance, as announced on October 16, 2016 and November 9, 2016, and a review of our actual results:

| ($ millions, except boe/d) | 2015 Revised Guidance | 2015 Actuals |
|---|---|---|
| Average production (boe/d) (1) | 5,700-5,900 | 5,637 |
| Capital expenditures & decommissioning expenditures (1) | $ 49 | $ 48 |
| Net debt (surplus) (2) (3) | $ (25)-(28) | $ (30) |

(1) Guidance originally released in our October 16, 2015 press release.
(2) Guidance originally released in our November 9, 2015 press release.
(3) Net debt (surplus) is a non-GAAP measure as defined under the heading "Non-GAAP Measures" at the end of this MD&A. This term does 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.

Our average production for 2015 was consistent with guidance reflecting decreased volumes resulting from the voluntary temporary shut-in caused by declining commodity pricing. Our actual capital expenditures were marginally better than our revised guidance reflecting our continued focus on cost savings while maintaining our safety and environmental standards. Aided by the $42.7 million proceeds on dispositions, the above factors contributed to a favorable net surplus of $29.6 million. It is anticipated that this surplus will fund our capital program for 2016 of $22 - $23 million. See "Outlook".

# Continuing Canadian Operations

## Petroleum and Natural Gas Production Volumes

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Crude oil (bbl/d) | **922** | 1,981 | **1,187** | 2,038 |
| Natural gas liquids (boe/d) | **364** | 778 | **510** | 779 |
| Natural gas (mcf/d) | **15,851** | 34,879 | **23,642** | 30,721 |
| Total (boe/d) | **3,928** | 8,572 | **5,637** | 7,937 |

### Total Production Volumes

Our production volumes for the current reporting periods decreased by 4,644 boe/d and 2,300 boe/d compared to the same periods of 2014. These decreases resulted from both the reported and comparative years' dispositions of producing properties that had associated production of 2,800 boe/d at the time of their sale. Scheduled third party plant restrictions and turnarounds also reduced our reported year's production. In addition, ongoing pipeline service restrictions and reduced system capacity have caused a severe negative impact on natural gas prices at Station 2 on the Spectra pipeline and CREC pricing on the Alliance pipeline system. We had responded to this depressed pricing by temporarily shutting in production volumes which were not tied to firm processing or transportation commitments with approximately 1,500 boe/d of production shut-in during the fourth quarter. Prior to then, we had also shut-in another 1,200 boe/d in response to lower commodity prices.

Partially offsetting these decreases was almost 500 boe/d of production during the reported year from our 2014/2015 winter drilling program that was focused on Montney and Dunvegan light crude oil in Grande Prairie, Alberta and Montney liquids rich natural gas on our Birley/Umbach, BC properties. Production from both of these properties was also negatively affected by temporary shut-ins during the fourth quarter as we responded to depressed pricing caused by pipeline capacity constraints. Late in 2014, we also acquired a 1,200 boe/d natural gas property in the Birley/Umbach area. This largely 100% owned and operated acquisition included key infrastructure which we believe strategic to the long term delivery of volumes from this area.

During the reported year we drilled, completed and equipped three wells (2.75 net) at Birley/Umbach. In mid-February 2016, we completed the additional 25 mmcf/d expansion of this compression facility allowing us to return a rented compressor. The net result will increase throughput capacity at this facility to 29 mmcf/d. Currently we have production from five wells (4.25 net) at Birley/Umbach and have capacity to add the volumes from a sixth standing well (0.75 net).

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

Natural gas production for the current reporting periods decreased compared to the same periods of 2014. These decreases resulted from the prior year's disposition of the predominantly natural gas and associated liquids' properties in the Gilby area with associated production of 4,800 mcf/d. Further contributing to these decreases was the fourth quarter disposition of our Rainbow properties with predominately natural gas production of 1,600 mcf/d. Partially offsetting the reporting year's decrease was natural gas production associated with both last year's property acquisitions and our successful drilling program in the Birley/Umbach area. During most of the fourth quarter, pipeline service restrictions and reduced system capacity in northeastern BC forced us to shut-in these properties.

As a result of the disposition of the Gilby properties and production constraints on our Montney liquids rich play we are reporting decreases in the current reporting periods' NGL production of 414 boe/d and 269 boe/d compared to the same periods of 2014.

## *Crude Oil Production Volumes*

Our crude oil production volumes for the current reporting periods decreased by 1,059 bbl/d and 851 bbl/d compared to the same periods of 2014. These decreases partially resulted from the sale of producing properties in the Karr area of Alberta, which closed on January 6, 2015. These sold properties had associated production of 485 boe/d at their time of sale. Also contributing to these decreases was last year's dispositions including our former Boundary Lake properties. Partially offsetting the decreases in crude oil volumes was the production from an Albright well and a Montney prospect at Gold Creek that both came on-stream during the fourth quarter of 2014.

## Petroleum and Natural Gas Revenues and Realized Pricing

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands, except per unit amounts) | **2015** | 2014 | **2015** | 2014 |
| Oil sales | **$ 4,066** | $ 12,907 | **$ 22,997** | $ 67,448 |
| $/bbl | **47.93** | 70.84 | **53.08** | 90.68 |
| Natural gas liquids sales | **$ 1,025** | $ 3,439 | **$ 6,671** | $ 18,496 |
| $/boe | **30.59** | 48.05 | **35.83** | 65.02 |
| Natural gas sales | **$ 3,044** | $ 11,456 | **$ 21,538** | $ 51,501 |
| $/mcf | **2.09** | 3.57 | **2.50** | 4.59 |
| Petroleum & natural gas revenue | **$ 8,135** | $ 27,802 | **$ 51,206** | $ 137,445 |
| $/boe | **22.51** | 35.26 | **24.89** | 47.44 |

Our petroleum and natural gas revenues of $8.1 million and $51.2 million during the current reporting periods decreased compared to the same periods of 2014. These decreases were caused by both lower realized commodity pricing and sales volumes. The decrease in our realized commodity pricing was due to lower benchmarks whose decline accelerated starting in the fourth quarter of 2014. These decreased benchmark prices resulted in realized pricing that lowered by 32% for oil during the fourth quarter to 46% for natural gas for the reported year. Our ratio of the comparatively higher priced crude oil sales, relative to total sales volumes, decreased during the reported year to 21% from 26% in the same period of 2014. This further contributed to the lower realized weighted average commodity pricing. This decreased ratio was the result of the disposition of our oil weighted Karr properties in addition to the disposition of other properties in combination with the 2014 acquisition of natural gas weighted properties.

## Benchmark Prices

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Crude oil | | | | |
| Canadian light sweet (1) ($/bbl) | **$ 52.55** | $ 74.37 | **$ 57.45** | $ 93.99 |
| Natural gas liquids | | | | |
| WTI (2) ($US/bbl) | **$ 42.18** | $ 73.15 | **$ 48.80** | $ 93.00 |
| Natural gas | | | | |
| AECO gas (3) ($/mcf) | **$ 2.50** | $ 3.65 | **$ 2.59** | $ 4.57 |

(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 conventional crude oil production is sold at prices based on the Canadian light sweet benchmark postings adjusted for quality. This benchmark price decreased during the current reporting periods, as did our average realized crude oil prices, compared to the same periods of 2014.

### 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 current reporting periods, and consistent with the decrease in the Canadian light sweet oil benchmark, our realized NGL price of $30.59/boe and $35.83/boe decreased compared to $48.05/boe and $65.02/boe for the same periods of 2014. The ratio of our NGL price relative to Canadian light sweet oil for the current reporting periods was approximately 60% compared to 68% for the comparative periods of 2014. The decreases in this ratio was due to a lower average price for propane which fell by 64% and 86% during the current reporting periods compared to the same periods of 2014.

### Natural Gas Pricing

Our realized natural gas price of $2.09/mcf and $2.50/mcf for the current reporting periods decreased from $3.57/mcf and $4.59/mcf for the same periods of 2014. These decreases were due to both an increase in the ratio of our production from BC in addition to lower benchmark pricing. In BC, various pipeline restrictions caused industry volume increases on the Spectra and Alliance pipelines and correspondingly, downward price pressures on Station 2 and CREC pricing.

## Royalties

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands, except where noted) | **2015** | 2014 | **2015** | 2014 |
| Royalties (recovery) | **$ (865)** | $ 3,737 | **$ 1,505** | $ 18,783 |
| Per sales ($/boe) | **$ (2.39)** | $ 4.74 | **$ 0.73** | $ 6.48 |
| Percent of revenues (%) | **(11)** | 13 | **3** | 14 |

For the current reporting periods, our royalties decreased on an overall basis, per boe and as a percentage of revenue, compared to the same periods of 2014. These decreases primarily resulted from adjustments to our Gas Cost Allowance (“GCA”) that included a fourth quarter adjustment of approximately $1.5 million. This resulted in a royalty recovery during that period. These GCA adjustments have since been collected. In addition, the decreases in our royalties on an overall, on a boe and percentage basis resulted from lower realized prices in the current reporting periods compared to the same periods of 2014. Lower commodity pricing caused a decrease in royalty rates where such rates are based on a sliding pricing scale.

During the first quarter of 2016, the Alberta Government announced that it would adopt the recommendations of the Royalty Review Advisory Panel and as a result will not be adopting any changes to the royalty structure for wells drilled prior to January 1, 2017.

## Commodity Price Risk Management Contracts

During the fourth quarter our outstanding derivative contract expired and as a result, at December 31, 2015, there were no outstanding commodity price derivative contracts. From time to time we enter into financial derivative contracts to help mitigate commodity price risk and assist us in better managing our future funds from operations. This provides more certainty as to what we will receive on a portion of our crude oil and/or natural gas sales volumes. While risk management 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 contracts.

When we have derivative contracts outstanding as at the end of a reporting period, they are reported at their estimated fair value on the date of the Financial Statements. This estimated fair value is partially determined through the difference in the referenced market forward price of the respective commodity over the remaining periods of the contracts compared to our received price multiplied by the remaining notional volumes. Volatility in 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 derivative contracts. Realized gains or losses on the derivative contracts are recognized in net income (loss) over the term of the financial derivative contract.

For the current reporting periods and their comparative periods of 2014, we reported the following realized and unrealized gains and losses on our derivative contracts:

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Realized (gains) losses on derivative contracts | **$ (455)** | $ (668) | **$ (1,587)** | $ 2,933 |
| Unrealized losses (gains) on derivative contracts | **391** | (2,065) | **1,481** | (2,428) |
| Total | **$ (64)** | $ (2,733) | **$ (106)** | $ 505 |

During the current reporting periods we realized gains on our AECO derivative contract as this benchmark was lower than our received fixed price of $3.50/GJ. If we had included these settlements in our natural gas revenues, we would have reported adjusted natural gas sales prices for the current reporting periods of $2.40/mcf and $2.68/mcf compared to our reported prices of $2.09/mcf and $2.50/mcf.

Our unrealized losses for the current reporting periods resulted from the AECO derivative contract's unrealized fair value becoming realized over its term.

## Production and Operating Expense

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands, except where noted) | **2015** | 2014 | **2015** | 2014 |
| Production & operating | **$ 6,529** | $ 15,742 | **$ 36,628** | $ 56,324 |
| Less: | | | | |
| Processing & gathering revenues | **(1,407)** | (848) | **(3,873)** | (5,308) |
| Net production & operating expense (1) | **$ 5,122** | $ 14,894 | **$ 32,755** | $ 51,016 |
| Per sales net production & operating expenses ($/boe) (1) | **$ 14.17** | $ 18.89 | **$ 15.92** | $ 17.61 |
| Per sales production & operating expenses ($/boe) | **$ 18.07** | $ 19.96 | **$ 17.80** | $ 19.44 |

(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 current reporting periods' production and operating expenses of $6.5 million and $36.6 million decreased compared to the same periods of 2014. These decreases partially resulted from the dispositions of properties at Gilby and Karr during 2014 and the first quarter of 2015, respectively. Our disposition at Rainbow also lowered production and operating expenses; however, its impact on these costs was not significant due to the timing of the disposition late in the fourth quarter. Also contributing to these decreases was the voluntary shut-in of relatively higher operating cost/lower netback wells. These wells are mostly located on our Hoffard, Pouce Coupe, Marten Hills, Whitecourt, Enchant and Rigel properties. Further decreases in these costs were due to the associated production from the voluntary temporary shut-in of natural gas production in response to decreased commodity prices in BC, which included our recently developed properties at Birley/Umbach. Finally, a favorable one-time equalization from an operating partner, as since collected, and a detailed review of our cost structure, including cost reduction efforts contributed to these decreases.

On a per boe basis, for the same reasons as just discussed, with the exception of the Gilby disposition, operating costs in the current reporting periods decreased compared to the same periods of 2014. Both the Karr and Rainbow property dispositions had a higher average operating cost per boe. Through these dispositions, we lowered our per boe average operating costs.

In response to the recent decline in commodity pricing we achieved significant cost reductions. We achieved these improvements through the shut-in of existing production with relatively higher operating costs per boe in addition to cost reductions principally through optimization of field staff, renegotiated hauling costs and a comprehensive evaluation of our use of chemicals and selective repairs and maintenance without compromising our commitment to health and safety.

The fourth quarter processing and gathering revenue increase compared to the same period of 2014 was the result of the previously mentioned operating partner's equalization. The revenues associated with this equalization were collected in the fourth quarter. For the reported year this revenue decreased primarily as a result of the comparative year's disposition of the Gilby area properties which included certain processing facilities and distribution pipelines.

## General & Administrative ("G&A") Expense

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands, except where noted) | **2015** | 2014 | **2015** | 2014 |
| G&A expense | **$ 3,002** | $ 3,356 | **$ 9,797** | $ 13,980 |
| Per sales ($/boe) | **$ 8.31** | $ 4.26 | **$ 4.76** | $ 4.83 |

We have continued to focus on improving our G&A cost structure and as a result of cost cutting initiatives have reduced our G&A expense, on an overall basis, during the current reporting periods compared to the same periods of 2014. We continue to assess our G&A expenses and make reductions where necessary. Our current reporting periods' decreases in G&A resulted from lower staffing costs caused by headcount reductions and less reliance on consultants. Beginning mid-way through the second quarter, we implemented a planned temporary reduction in our work week which saved us $0.5 million. We have recently announced to our staff a similar arrangement for 2016 in addition to benefit reductions. Further decreases resulted from renegotiated professional fees and software licence costs in addition to lower public company and corporate costs. For the current reporting periods, these decreases were achieved despite incurring $0.4 million and $0.8 million in severance costs from staffing reductions. Removing the effect of the non-reoccurring severance costs resulted in a reported year G&A expense of $4.37/boe.

On a boe basis, we achieved a decrease during the reported year despite lower production volumes compared to the same period of 2014 in addition to a focus on higher working interest properties and lower capital expenditures, both of which decreased our recoveries from our non-operating partners. Despite a decrease of $0.8 million in G&A expense during the fourth quarter, after excluding the $0.4 million of severance costs, as compared to the same quarter of 2014, the effect from both the lower volumes and recoveries was an increase in G&A on a boe basis.

We will continue to evaluate our existing G&A cost structure and implement cost savings initiatives.

## Netback

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| Per sales ($/boe) | **2015** | 2014 | **2015** | 2014 |
| Realized sales price | **$ 22.51** | $ 35.26 | **$ 24.89** | $ 47.44 |
| Less: | | | | |
| Royalties | **2.39** | (4.74) | **(0.73)** | (6.48) |
| Net production expense (1) | **(14.17)** | (18.89) | **(15.92)** | (17.61) |
| G&A expense | **(8.31)** | (4.26) | **(4.76)** | (4.83) |
| **Netback (1)** | **$ 2.42** | $ 7.37 | **$ 3.48** | $ 18.52 |

(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 netbacks for the current reporting periods significantly decreased compared to the same periods of 2014. These decreases resulted from lower commodity benchmark prices. As a result, our reported year realized prices were only 55% or 60% of the natural gas and associated liquid or crude oil prices, respectively, that we reported during the same periods of 2014.

For the reported year, the decrease in the proportion of crude oil sales relative to our total volumes resulted from both the disposition of higher oil weighted producing properties in the Karr area of Grande Prairie and higher natural gas production from our Birley/Umbach area. Generally, crude oil sales have had a higher netback than on an equivalent volume of natural gas as determined from its heating value. As a result, this change in proportion of crude oil sales resulted in decreases to both our reported year realized prices and netback. For the fourth quarter, the shut-in of natural gas production in BC, including at our Birley/Umbach properties, temporarily increased our weighting of crude oil production relative to our total volumes to an amount equal to the same period of 2014.

During the current reporting periods, the netback decreases caused by lower commodity benchmark pricing were partially offset by lower net production expenses and royalties on a boe basis. For the reported year, on a boe basis, and after excluding $0.8 million of non-recurring severance costs, a decrease in G&A also partially offset the effect of lower commodity pricing on our netback. Despite a decrease in our fourth quarter G&A costs of $0.8 million after excluding severance costs, the effect of lower volumes caused the per boe measure to be higher compared to the same quarter of 2014. The actions we undertook early in the reported year to shut-in high operating cost/lower netback volumes in addition to the fourth quarter shut-in of BC production in response to volatile natural gas pricing preserved our netback from further deterioration.

## Exploration and Evaluation Expense

| | **Three months ended December 31** | | **Year ended December 31** | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Exploration & evaluation expenditures | **$ 731** | $ 569 | **$ 1,648** | $ 1,632 |

Exploration and evaluation expense reported during the current reporting and comparative periods were due to salaries, pre-licensing evaluation and exploratory lease rental costs.

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

| | **Three months ended December 31** | | **Year ended December 31** | |
|---|---|---|---|---|
| ($ thousands, except where noted) | **2015** | 2014 | **2015** | 2014 |
| Depletion, depreciation & amortization | **$ 5,560** | $ 12,677 | **$ 32,508** | $ 48,813 |
| Depletion per sales ($/boe) | **$ 12.76** | $ 15.03 | **$ 14.02** | $ 15.83 |

DD&A expense decreased on an overall basis during the current reporting periods compared to the same periods of 2014. These decreases resulted from lower depletion rates and production volumes. The decreases in our depletion rates was due to the impact of lowering the 2015 carrying value of our development and production assets (“D&P Assets”) to its recoverable value through recognizing an impairment charge during the comparative year of $63.5 million. We also are reporting a fourth quarter decrease in the carrying value of our D&P Assets through an impairment charge of $75.0 million as initially reported in the third quarter. In addition, our depletion rates decreased as a result of the disposition of the Karr producing properties with their higher associated rate. The increase in our amortization expense resulted from the 25 additional sections of 100% working interest undeveloped lands in the Birley/Umbach area that we acquired at the May 2014 and November 2014 Crown land sales.

The increase in our total proved and probable reserves from 27,383 mboe at December 31, 2014, to 30,634 mboe at December 31, 2015, was adjusted for production and then applied in determining our fourth quarter depletion rate. However, this increase was more than offset by higher future development costs, which were also included in our depletion rate, of $95.0 million at December 31, 2015 compared to $71.0 million at December 31, 2014.

## Impairment of Development and Production Assets

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands, except where noted) | **2015** | 2014 | **2015** | 2014 |
| Impairment of development & production assets | **$ -** | $ 63,500 | **$ 75,000** | $ 63,500 |

During the reported year, we identified triggers indicating impairment in the carrying values of our D&P assets. These triggers resulted from a significant reduction in both short and long-term forward Canadian petroleum and natural gas prices. The carrying value of our D&P Assets was already sensitive to changes in forward commodity prices as we provided for impairment totalling $63.5 million against all three of our cash generating units ("CGUs") in the fourth quarter of 2014. Upon reporting that impairment charge, each CGU's carrying value approximated its recoverable value. Given continued forward commodity price deterioration, we then performed an impairment test of each CGU's carrying values as at September 30, 2015. This testing revealed impairment in each of our CGU's totalling $75.0 million. On the December 31, 2015 carrying values, we again re-tested for impairment on each CGU. This subsequent test did not reveal any further impairment. Although forward pricing further deteriorated between September 30, 2015 and December 31, 2015, this impact on each CGU's recoverable value was offset by additional proved undeveloped and probable reserves.

For both of the reporting years' impairment tests, in addition to the comparative year's test, each CGU's recoverable value was estimated using a value in use calculation based on expected future net revenues anticipated to be produced from proved plus probable reserves, using an average discount rate that could range from 10% to 20%, depending on the category of reserves, and the following forward commodity price estimates:

| | Edmonton Light Crude Oil ($/bbl) (1) | | AECO Gas ($/mmbtu) (2) | |
|---|---|---|---|---|
| **As at December 31** | **2015 (3)** | **2014 (4)** | **2015 (3)** | **2014 (4)** |
| 2016 | $ 50.74 | $ 83.20 | $ 2.56 | $ 4.00 |
| 2017 | $ 66.40 | $ 88.90 | $ 3.20 | $ 4.25 |
| 2018 | $ 72.80 | $ 94.60 | $ 3.55 | $ 4.50 |
| 2019 | $ 80.90 | $ 99.60 | $ 3.85 | $ 4.70 |
| 2020 | $ 83.20 | $ 104.70 | $ 3.95 | $ 5.00 |
| Thereafter | 1.94% to 2.07%/yr | 1.94% to 2.07%/yr | 1.6% to 3.77%/yr | 1.6% to 3.77%/yr |

(1) Central market point for Canadian crude oil.
(2) Central market point for Canadian natural gas.
(3) Source: 2016 forward strip pricing per Bloomberg. 2017 and onwards is per McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2016.
(4) Source: McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2015

## Exploration & Evaluation Assets ("E&E Assets")

Given the reporting year's decreases in crown undeveloped land sales both for activity and prices, we tested the E&E Assets carrying value at December 31, 2015 for impairment. Management gathered recent crown undeveloped land sales and compared the relevant sales prices against the petroleum and natural gas formations in our own portfolio of undeveloped lands. This testing, conducted at a Canadian level, did not reveal the presence of impairment.

## Gains on Disposition of Properties

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Gains on disposition of properties | **$ (1,544)** | $ (12,204) | **$ (23,331)** | $ (15,124) |

During the reporting and comparative years we completed the sale of several properties for aggregate adjusted proceeds of $42.8 million and $35.6 million, respectively. The reporting year dispositions included the sale of certain petroleum and natural gas properties including undeveloped lands located in the Karr area of northwestern Alberta, which was completed on January 6, 2015. At December 31, 2014, the Karr properties were classified as held for sale. This classification included carrying values of $23.1 million for both exploration and evaluation assets and D&P Assets and $0.8 million for decommissioning obligations. Included in the comparative periods were also several dispositions. These included the sale of the Gilby area for net proceeds of $28.1 million.

During the fourth quarter we disposed of our natural gas weighted Rainbow properties located in the northwest corner of Alberta. This sale resulted in the reported $1.5 million gain. Although proceeds on this transaction were insignificant, the fourth quarter gain resulted from these properties associated decommissioning obligations of $9.1 million.

During the reported year, we participated in several other dispositions and three swap transactions. We assessed the fair value of undeveloped lands received in the swap transactions based on fair values totalling $2.0 million for the undeveloped lands we gave up. We used recent market sales transactions of similar properties and lands to determine their fair value.

## Share-Based Compensation

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Share-based compensation | **$ 599** | $ 377 | **$ 2,370** | $ 938 |

Late in the second quarter, we granted more restricted and performance awards compared to the same period of 2014. During the current reporting periods this higher number of granted awards resulted in an increase in the reported amortization of the fair value assigned to these awards as compared to the same periods of 2014. We also are reporting the amortization of the fair value assigned to the June 2014 restricted and performance awards grants half of which were settled in the second quarter. Finally, the increase in share-based compensation included amortizing the fair value of share options granted late in 2014 and throughout 2015, including those granted in December 2015. Combined, the June 2014 and 2015 restricted and performance awards and option grants increase the reported year's share-based compensation compared to the same period of 2014.

## Bad Debt Expense

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Bad debt expense | **$ 518** | $ 1,041 | **$ 1,072** | $ 1,206 |

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 our reported year, we identified joint arrangement partners that have either filed for creditor protection or have since become insolvent. As a result, for the current reporting periods we provided for $0.6 million and $1.1 million of receivables that were deemed uncollectible.

## Foreign Exchange (Gains) Losses & Other

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Foreign exchange (gains) losses & other | **$ (98)** | $ 87 | **$ (639)** | $ (2,293) |

During the current reporting periods we recognized foreign exchange gains from holding a US dollar cash position. This position acts as an economic hedge to the US dollar denominated payables we accrued as indemnifications to the buyer of the Discontinued Operations.

## Financing Expenses

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Interest & financing charges (income) | **$ (134)** | $ 131 | **$ (243)** | $ 2,634 |
| Amortization of deferred financing costs | **-** | - | **-** | 343 |
| Accretion of decommissioning obligation | **611** | 681 | **2,476** | 2,712 |
| Total | **$ 477** | $ 812 | **$ 2,233** | $ 5,689 |

Interest and financing income of $0.2 million for the year to date includes interest income from our cash deposits of $37.9 million at December 31, 2015, in addition to other miscellaneous interest income as partially offset by standby fees on our credit facility. The interest income we receive on our cash deposits is competitive to other short-term liquid investments. For the first half of 2015, the standby fees were based on a credit facility availability of $125.0 million. This availability was first reduced to $75.0 million late in the second quarter of 2015 and as discussed under the section “Credit Facility” of this MD&A, the facility agreement was further amended resulting in a revised availability of $50.0 million in the fourth quarter. Both of these decreases resulted from lower forward commodity pricing and property dispositions. We intend to remain undrawn on this facility throughout 2016 given our $29.6 million of working capital can finance our existing $22.0 - $23.0 million capital program. As we anticipate we will remain undrawn on our credit facility, we would not be affected by a possible decrease at the June 2016 redetermination of its availability resulting from lower proved developed reserves as included in our 2015 year-end reserve report.

During the comparative year we incurred interest expense at an average effective interest rate of 4.1% on our average outstanding credit facility balance in addition to standby fees on the available balance. During the third quarter of 2014, we repaid all of the $78.5 million outstanding credit facility balance using the proceeds from the sale of the Discontinued Operations. In conjunction with this repayment, we accelerated the amortization of the remaining deferred financing costs.

The accretion charges during the current reporting periods had a modest decrease compared to the same periods of 2014. These decreases resulted from applying a lower average discount rate when accounting for the passage of time related to the decommissioning obligation. As included in our December 31, 2015 carrying value of decommissioning obligations, we have updated for a lower risk-free discount rate. This should result in lower accretion charges during 2016.

### Income Tax Expense

The Alberta Government raised the provincial corporate tax rate, as substantively enacted on September 29, 2015, by two percent. Given we currently do not report our deferred tax assets because it is not probable that we will be able to utilize these assets against future tax profits, we are not reporting a deferred income tax recovery. At December 31, 2015, we had the following tax pools:

| ($ thousands) | **December 31 2015** |
|---|---|
| Canadian oil & gas property expense | **$ 32,193** |
| Canadian development expense | **80,416** |
| Canadian exploration expense | **56,553** |
| Undepreciated captial costs | **50,702** |
| Non-capital losses | **211,183** |
| Other | **3,750** |
| Total | **$ 434,797** |

At December 31, 2015, we did not recognize deferred tax assets related to $211 million of tax losses. Based on our expected cash flow and available tax pools, we do not expect to incur corporate taxes in the near term.

## Discontinued Operations

The operating results for the Discontinued Operations are shown in the following table for the period ending August 19, 2014:

| | **August 19 2014** |
|---|---|
| Income from ordinary activities of discontinued operations | $ 6,576 |
| Gain on sale of discontinued operations | 1,037 |
| Realized accumulated other comprehensive income on disposition of foreign operations | 9,546 |
| Income taxes of discontinued operations | (4,887) |
| **Net income from discontinued operations, net of income taxes** | **$ 12,272** |

During the reported year we paid $1.9 million, as drawn from our December 31, 2014 provision, which was reported on the statements of cash flows as Discontinued Operations in investing activities.

The August 19, 2014 net assets of this Discontinued Operation, was less than the disposition proceeds of $140.5 million, net of transaction costs. This resulted in a gain on the sale of discounted operations of $1.0 million.

Upon the completion of the sale of the Discontinued Operations, we recognized $9.5 million of realized foreign exchange as included in net income from discontinued operations. This amount had previously been accumulated from foreign currency translations of the Discontinued Operations' net assets and reported as other comprehensive income.

# Net and Comprehensive Loss

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands, except where noted) | **2015** | 2014 | **2015** | 2014 |
| Weighted average shares outstanding - basic & diluted (thousands) | **215,337** | 215,081 | **215,197** | 214,601 |
| **Net loss from continuing operations** | **$ (5,303)** | $ (58,311) | **$ (83,606)** | $ (50,672) |
| Per share - basic & diluted ($/share) | **$ (0.02)** | $ (0.27) | **$ (0.39)** | $ (0.24) |
| **Net (loss) income from discontinued operations** | **$ -** | $ (2,037) | **$ -** | $ 12,272 |
| Per share - basic & diluted ($/share) | **$ -** | $ (0.01) | **$ -** | $ 0.06 |
| **Net loss** | **$ (5,303)** | $ (60,348) | **$ (83,606)** | $ (38,400) |
| Per share - basic & diluted ($/share) | **$ (0.02)** | $ (0.28) | **$ (0.39)** | $ (0.18) |
| **Comprehensive loss** | **$ (5,303)** | $ (60,349) | **$ (83,606)** | $ (44,641) |
| Per share - basic & diluted ($/share) | **$ (0.02)** | $ (0.28) | **$ (0.39)** | $ (0.21) |

We reported net losses from Continuing Canadian Operations for the current reporting periods and their comparative periods of 2014. Contributing to the current reporting periods net losses, compared to the same periods of 2014, were lower petroleum and natural gas revenues due to the effect of both lower sales volumes and realized commodity prices. Partially offsetting the decreased commodity revenues were lower charges for operating, royalties, G&A, depletion and financing costs. The reported year's net loss also includes an increased impairment charge of $75.0 million, as initially reported in the third quarter, compared to $63.5 million reported in the fourth quarter of 2014. As these impairment charges were reported in different quarters, this resulted in a decrease in the fourth quarter's net loss compared to the same quarter of 2014.

Our net loss for the comparative periods includes the results from both our continuing and Discontinued Operations. As previously mentioned, our Discontinued Operations were sold on August 19, 2014. During the fourth quarter of 2014, we were made aware of and correspondingly increased expenses by $2.1 million upon assessing the probable outflow of resources related to the indemnifications we made to the purchaser pursuant to a share purchase and sale agreement dated as of June 14, 2014 (the "PSA"). For the comparative year our Discontinued Operations net income included the realization of $9.5 million of foreign exchange gains as accumulated from the revaluation of the US dollar denominated net assets of these operations into Canadian dollars but as offset in other comprehensive income. This realization resulted from the disposition of these operations. The effect was to decrease the comparative year's net loss but as offset by an increase in the other comprehensive loss. This move had a nil effect on the comparative year's comprehensive loss.

# Capital Resources, Capital Expenditures and Liquidity

As announced on October 16, 2015, we revised our 2015 capital program from $55.0 million to $49.0 million due to cost savings realized at Birley/Umbach on the completion of the three wells (2.75 net) in the third quarter. The average drill, complete, equip and tie-in costs for a well at Birley/Umbach was approximately $7.6 million per well in 2014, bringing our total to $22.8 million on a three well program. During 2015, we were able to drill and complete the three wells (2.75 net) including equipping and tie-in costs for $13.1 million for savings of approximately $9.7 million. This decrease in the capital budget did not delay our installation of the first phase of a facility expansion targeting our Montney resource at Birley/Umbach, BC, which was commissioned mid-February 2016. Expanding our Birley/Umbach facility has allowed us to commence production, during the first quarter of 2016, from an additional three wells in our Birley/Umbach area, bringing the total wells on production in this area to five wells.

During the fourth quarter, we renewed the availability of our credit facility at $50.0 million, a decrease from the previous availability of $75.0 million, resulting from lower forward commodity prices and proved developed reserves. We are currently undrawn on this facility. Our capital program for 2016 of $22.0 - $23.0 million, as detailed in the "Outlook" section of this MD&A, is anticipated to be funded through our existing net surplus position which included $37.9 million of cash on hand at December 31, 2015 and our funds from operations.

For the reported year, we financed our investment in capital, decommissioning, exploration and evaluation expenditures and non-cash working capital from cash on hand, funds from operations and proceeds from property dispositions, including the sale of the Karr properties.

## Funds from Operations

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands, except where noted) | **2015** | 2014 | **2015** | 2014 |
| Cash flow from continuing operating activities | **$ (868)** | $ 8,202 | **$ 3,381** | $ 46,257 |
| Add back: | | | | |
| Change in operating non-cash working capital and other | **397** | (3,065) | **1,764** | (791) |
| Provision expenditures | **1,987** | 932 | **3,888** | 2,692 |
| Funds from operations (1) | **$ 1,516** | $ 6,069 | **$ 9,033** | $ 48,158 |
| Per share - basic & diluted | **$ 0.01** | $ 0.03 | **$ 0.04** | $ 0.22 |
| Per sales ($/boe) | **$ 4.19** | $ 7.70 | **$ 4.39** | $ 16.62 |

(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.

During the current reporting periods, our funds from operations significantly decreased to $1.5 million and $9.0 million compared to $6.1 million and $48.2 million in the same periods of 2014. These decreases were due to considerably lower commodity pricing and sales volumes. The decreases in the commodity pricing resulted from significantly lower benchmark prices. The decreases in the sales volumes resulted from pipeline service restrictions and reduced system capacity throughout the year, scheduled plant restrictions and turnarounds, the Karr and Gilby property dispositions, voluntary and temporary shut-ins and capacity constraints at our Montney liquids rich development. Partially offsetting these decreases were realized gains from derivative contracts and lower cash costs.

On a boe basis, our funds from operations is higher than our netback because the cash finance income and the realized gain on our derivative contract are both included in the funds from operations, whereas they are excluded from our netback.

## Credit Facility

| | **December 31 2015** | December 31 2014 |
|---|---|---|
| ($ thousands) | | |
| Long-term debt | **$ -** | $ - |
| Add: | | |
| Accounts payable, accrued liabilities & other | **21,607** | 44,389 |
| Less: | | |
| Cash | **(37,947)** | (46,018) |
| Accounts receivable | **(11,173)** | (24,952) |
| Prepaids & deposits | **(2,101)** | (2,207) |
| Net debt (surplus) (1) | **$ (29,614)** | $ (28,788) |

(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 remained undrawn on our credit facility at December 31, 2015. We had a net surplus of $29.6 million at December 31, 2015, compared to $28.8 million at December 31, 2014. This positive change of $0.8 million was due to the proceeds of $42.8 million received mostly from the Karr property disposition and $9.0 million from funds from operations which excluded $0.9 million in foreign exchange gains on holding US denominated cash. Partially offsetting these increases were capital, decommissioning, exploration and evaluation expenditures in addition to other non-cash working capital adjustments totalling $51.9 million.

As announced on December 17, 2015, our reserve-based 364 day revolving credit facility (the "Revolving Term Credit Facility"), which we hold with a syndicate of Canadian banks, was amended following the completion of the semi-annual review. The amended Revolving Term Credit Facility provides a borrowing base of $50.0 million, down from $75.0 million at June 30, 2015 and $125.0 million at December 31, 2014, primarily as a result of significantly reduced commodity pricing and in the case of the second quarter's decrease, non-core asset dispositions. The Revolving Term Credit Facility is subject to re-determination on a semi-annual basis, with a maturity date of June 23, 2016, subject to further extension. At December 31, 2015 we had available credit equal to the full amount of our borrowing base. We were also undrawn on our Revolving Term Credit Facility at December 31, 2014, but had an outstanding letter of credit of $0.3 million, as secured by our lending syndicate, which reduced the available credit to $124.7 million.

The Revolving Term Credit Facility is collateralized by floating charges and security interests over all present and future properties and other assets.

## Capital Expenditures

Capital expenditures were as follows:

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ thousands) | **2015** | 2014 | **2015** | 2014 |
| Land & lease | **$ 550** | $ 4,054 | **$ 1,136** | $ 18,388 |
| Drilling & completions | **142** | 14,319 | **17,595** | 44,601 |
| Facilities & equipment | **8,904** | 5,128 | **24,176** | 16,200 |
| Field expenditures | **9,596** | 23,501 | **42,907** | 79,189 |
| Capitalized G&A | **395** | 259 | **1,351** | 1,110 |
| Furniture & equipment | **7** | 61 | **67** | 435 |
| Acquisitions | **-** | 15,850 | **-** | 15,850 |
| Total | **$ 9,998** | $ 39,671 | **$ 44,325** | $ 96,584 |

During the fourth quarter of 2015, we incurred the remaining costs of the first phase expansion of the compression facility in our Birley/Umbach area, as commissioned during the first quarter of 2016. This first expansion has increased our facility's capacity by 25 mmcf/d and eliminated the need for a rental compressor. The net result increased our throughput capacity at this facility to 29 mmcf/d. This has enabled us to produce from five of the wells we have drilled at our Birley/Umbach location.

## Property Acquisition

On November 6, 2014, we acquired primarily natural gas producing properties near our Birley/Umbach operations located in northeastern British Columbia along with operatorship of gas processing and transportation infrastructure. The purchase price was comprised of both cash of $15.8 million, after adjustments, and 3.5 sections of undeveloped lands in the Wapiti area of Alberta which had an estimated fair value of $5.0 million. Production from the acquired producing wells was approximately 1,200 boe/d at the time of their acquisition.

## Rationalization of Properties

We may from time to time, dispose of properties so that we can focus on the immediate development of Montney liquids rich natural gas on our Birley/Umbach BC properties and in the near future our Montney and Dunvegan light crude oil in Grande Prairie, Alberta. As a result, during the year to date we completed the sale of petroleum and natural gas properties including undeveloped lands located in the Karr and Rainbow areas of northwestern Alberta in addition to other minor dispositions and customary closing adjustments, for net proceeds of $42.8 million. The Karr properties were classified as held for sale at December 31, 2014. Our production from all our 2015 property dispositions immediately prior to their sale was 930 boe/d.

## Non-Monetary Property Swaps

During the reported year, we participated in three swap transactions. We determined that the fair value of the properties and lands that we swapped for undeveloped lands was $2.0 million. The carrying amount of these swapped properties, in addition to the carrying value for other insignificant dispositions, was $0.6 million.

## Accrued Transaction and Indemnification Costs on Discontinued Operations

We are subject to certain obligations guaranteed in favour of the buyer in connection with the sale of the Discontinued Operations on August 19, 2014. We have guaranteed the payment of the indemnification obligations of Storm BVI, a wholly-owned subsidiary, under a share purchase and sale agreement with the buyer dated as of June 14, 2014. These obligations relate to any 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 claims under these indemnification obligations could result in a substantial payment by us to the buyer.

We received claims under the agreement from the buyer of the Discontinued Operations at December 31, 2015, totaling $16 million as it received from a former Tunisian service provider and the Tunisian Tax Authority. Storm BVI has provided the buyer indemnifications for claims of this nature which are guaranteed by us. As of December 31, 2015, an estimate of possible future disbursements for these indemnifications, including professional costs, totaled $1.2 million (2014 - $2.8 million) and is recorded in accounts payable, accrued liabilities and other on the statement of financial position. During the year to date, 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, we are of the view that such claims are without merit and will represent the company's interests vigorously in any future legal or arbitration proceedings.

## Provisions

Our provision balance primarily relates to the future abandonment and reclamation of our properties. At December 31, 2015, we had a provision of $98.1 million (December 31, 2014 - $106.7 million). We estimate the net present value of the total decommissioning obligation based on a total future undiscounted and uninflated liability of $99.5 million (December 31, 2014 - $117.6 million).

During the reported and comparative years, we reported increases in our decommissioning liability of $2.2 million and $29.6 million, respectively, due to changes in estimates which were substantially due to decreases in the risk free rate. During the reported year we also incurred additions related to our drilling program and the expansion of our facility at Birley/Umbach of $0.7 million (same period of 2014 - $3.0 million related to an acquisition and our drilling program) and recorded accretion charges. The recognized accretion charges reflect the increase in the obligation associated with the passage of time. For the current reporting periods, accretion charges were modestly lower when compared to the same periods of 2014 due to a lower applied discount rate.

Partially offsetting these increases in the decommissioning obligation during the reported and comparative years were abandonment and reclamation expenditures related to our Canadian properties of $3.7 million and $2.7 million, respectively. In addition, the decommissioning obligation decreased as a result of property dispositions of $9.4 million (same period of 2014 – dispositions and the classification of certain properties as held for sale for $11.3 million and $0.8 million, respectively).

As at December 31, 2015 and December 31, 2014, 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, 2015, a risk-free interest rate of 2.16% was used in order to calculate the present value of the obligation (December 31, 2014 - 2.33%).

## 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 2015** | December 31 2014 |
|---|---|---|
| Common shares outstanding | **215,349,412** | 215,082,199 |
| Share options | **9,465,617** | 10,529,675 |
| Restricted awards | **1,084,226** | 206,590 |
| Performance awards | **1,006,996** | 244,375 |
| Weighted average common shares - basic and diluted | **215,196,938** | 214,600,915 |

As at March 6, 2016, we had 215,349,412 common shares, 9,260,618 share options, 1,071,321 restricted awards and 999,356 performance awards outstanding.

## Commitments and Guarantees

At December 31, 2015, 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) | 2016 | 2017 | 2018 | 2019 | 2020 | Thereafter | Total |
| Office leases | $ 2,381 | $ 2,400 | $ 2,400 | $ 1,921 | $ - | $ - | $ 9,102 |
| Operating & transportation contracts | 3,385 | 1,338 | 1,019 | 924 | 829 | 202 | 7,697 |
| | **$ 5,766** | **$ 3,738** | **$ 3,419** | **$ 2,845** | **$ 829** | **$ 202** | **$ 16,799** |

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 the firm pipeline capacity or benefit from the operating services.

We are involved in litigation and claims arising in the normal course of operations and from indemnifications provided to the buyer of the Discontinued Operations. Such claims are not expected to have a material impact on our results of operations or cash flows. See “Risk Factors”.

## Off Balance Sheet Arrangements

We did not enter into any off balance sheet arrangements during the reporting period.

## Related Party Transactions

We determined that the 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 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 $2.6 million and $2.5 million, respectively. Long-term incentive benefits for our officers and directors as included in share-based compensation for the reported and comparable years totaled $1.3 million and $0.5 million, respectively.

The former officers associated with the Discontinued Operations, as included in net income from discontinued operations, net of taxes, were paid salaries plus other benefits and share-based compensation for the comparable year totaling $2.5 million, including $1.6 million in severance costs.

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 37.4% 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") (a wholly owned subsidiary of our company and the general partner of WOGH Limited Partnership) 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 $1.7 million and $1.3 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% and 19% of its and our combined Canadian production volumes. At December 31, 2015, $0.2 million of this G&A recovery was included in accounts receivable (December 31, 2014 - $0.3 million).

# Outlook

Our capital program for the first half of 2016 includes the final commissioning of the recently expanded Birley compressor which occurred in mid-February. However, as a result of unfavourable commodity pricing, we have elected to defer the previously announced, capital program originally slated for the first half of 2016, including $8 million to drill, complete, equip and tie-in four (3.5 net) Dunvegan oil wells at Albright in the Grande Prairie area. This drilling was to commence in the first quarter, with anticipated production to occur in April or May 2016.

Natural gas pricing in British Columbia will be a key determinant in the amount of capital, if any, dedicated to our Birley/Umbach development in the second half of 2016. We realized material cost savings at Birley/Umbach in 2015 by conducting completion operations after spring break-up. Subject to commodity pricing, in an effort to again capture these seasonal cost savings in 2016, and to accommodate the short term facility constraints associated with the high initial production rates from wells brought into our new facility in February, our Birley/Umbach drilling program is anticipated to commence in the second half of 2016 (3 gross wells, 2.67 net) for a cost of approximately $13.8 million. The total 2016 capital program is anticipated at $22.0 million - $23.0 million, dependent on economic factors.

In 2015, we confirmed the scale of the Montney resource across our Birley/Umbach lands and are committed to developing this core asset prudently and efficiently during this period of depressed natural gas prices. We have set a capital program that addresses the need for flexibility in a challenging business environment. We continue to maintain one of the strongest balance sheets among our peers, which will allow us the optionality to quickly adjust our capital spending in response to market factors while still adding value for our shareholders by expanding the size of our resources with a selective drilling and completion program. We will continue to focus on capital discipline and cost control while maintaining our commitment to safety.

Our 2016 guidance is based on a three well Birley/Umbach capital program (dependent on economic factors) as follows:

| ($ millions, except boe/d) | 2016 Guidance |
|---|---|
| Average production (boe/d) | 5,700 - 5,800 |
| Exit production (boe/d) | 7,300 - 7,500 |
| Capital expenditures | $22 - $23 |

# Selected Annual Information

Summarized information by year for the three years ended December 31, 2015, appears below:

| Year ended December 31 | 2015 | 2014 | 2013 |
|---|---|---|---|
| ($ thousands, except per share amounts) | | | |
| Petroleum & natural gas revenue, net of royalties from Continuing Canadian Operations | **$ 49,701** | $ 118,662 | $ 101,433 |
| Net loss from Continuing Canadian Operations (1) | **$ (83,606)** | $ (50,672) | $ (9,453) |
| Per share - basic & diluted ($/share) | **$ (0.39)** | $ (0.24) | $ (0.03) |
| Net loss (1) (2) | **$ (83,606)** | $ (38,400) | $ (26,700) |
| Per share - basic & diluted ($/share) | **$ (0.39)** | $ (0.18) | $ (0.12) |
| Total assets (1) | **$ 321,564** | $ 434,318 | $ 555,341 |
| Long-term financial liabilities (3) | **$ 96,042** | $ 106,726 | $ 174,984 |

(1) Includes $75 million, $63.5 million and $3.5 million of impairment charges against Continuing Canadian Operations for the years ended December 31, 2015, 2014 and 2013, respectively.

(2) Includes net income from the Discontinued Operations which were sold on August 19, 2014. We also reported $32.0 million in impairment charges against the Discontinued Operations for the year ended December 31, 2013.

(3) Includes loans and borrowings, provisions and other long-term liabilities.

## Factors That Have Caused Variations over the Years

Decreased sales volumes as a result of our non-core property dispositions lowered our petroleum and natural gas revenues, net of royalties during the year ended 2013. Results of our successful drilling campaign in northwestern Alberta and northeastern British Columbia and increases in commodity prices resulted in an increase in our petroleum and natural gas revenues, net of royalties for 2014. During the reported year a significant decrease 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, resulted in a significant decrease in our petroleum and natural gas revenues, net of royalties.

Our net losses from the Continuing Canadian Operations for the years ended 2013, 2014 and 2015 were negatively impacted by impairment charges against our CGUs resulting from decreases in forward commodity pricing. These impairment charges, in addition to our non-core property disposition program, 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.

Our net loss for the year ended 2013 was also impacted by an additional $32.0 million impairment charge against the Discontinued Operations. Further decreasing total assets and long-term financial liabilities during 2014 was the disposition of the Discontinued Operations which closed August 19, 2014, which included the repayment of outstanding debt of $78.5 million during the year ended 2014. At the end of 2014 and 2015 there was no outstanding long-term debt. Further decreases in long-term financial liabilities during the reported year resulted from a decrease in the estimated decommissioning obligation primarily caused by the use of a lower inflation rate in addition to a reduction in the obligations associated to property dispositions.

Please refer to “Continuing Canadian 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 Continuing Canadian Operations

Summarized information by quarter for the two years ended December 31, 2015, appears below:

| | **Dec. 31 2015** | Sept. 30 2015 | Jun. 30 2015 | Mar. 31 2015 | Dec. 31 2014 | Sep. 30 2014 | Jun. 30 2014 | Mar. 31 2014 |
|---|---|---|---|---|---|---|---|---|
| **CONTINUING CANADIAN OPERATIONS (except where noted)** | | | | | | | | |
| **Production Volumes** | | | | | | | | |
| Crude oil (bbl/d) | **922** | 1,065 | 1,284 | 1,485 | 1,981 | 1,823 | 2,267 | 2,084 |
| Natural gas liquids (boe/d) | **364** | 395 | 604 | 682 | 778 | 678 | 715 | 950 |
| Natural gas (mcf/d) | **15,851** | 20,641 | 25,290 | 33,007 | 34,879 | 29,028 | 29,570 | 29,364 |
| Average daily production (boe/d) | **3,928** | 4,900 | 6,103 | 7,668 | 8,572 | 7,339 | 7,911 | 7,928 |
| **Sales Prices** | | | | | | | | |
| Average oil price ($/bbl) | **$ 47.93** | $ 51.34 | $ 62.90 | $ 49.03 | $ 70.84 | $ 93.10 | $ 101.01 | $ 96.41 |
| Average natural gas liquids price ($/boe) | **$ 30.59** | $ 31.68 | $ 41.06 | $ 36.47 | $ 48.05 | $ 64.71 | $ 72.06 | $ 74.10 |
| Average natural gas price ($/mcf) | **$ 2.09** | $ 2.56 | $ 2.50 | $ 2.65 | $ 3.57 | $ 4.11 | $ 4.89 | $ 6.01 |
| **Netback** (1) | | | | | | | | |
| Average commodity pricing ($/boe) | **$ 22.51** | $ 24.48 | $ 27.67 | $ 24.15 | $ 35.26 | $ 45.37 | $ 53.75 | $ 56.50 |
| Royalties ($/boe) | **$ 2.39** | $ (1.13) | $ (0.78) | $ (2.07) | $ (4.74) | $ (6.90) | $ (8.47) | $ (6.01) |
| Net production expenses ($/boe) (1) | **$ (14.17)** | $ (12.49) | $ (18.36) | $ (17.04) | $ (18.89) | $ (17.44) | $ (17.06) | $ (16.91) |
| G&A expense ($/boe) | **$ (8.31)** | $ (4.39) | $ (3.70) | $ (4.00) | $ (4.26) | $ (4.32) | $ (4.30) | $ (6.46) |
| Netback ($/boe) (1) | **$ 2.42** | $ 6.47 | $ 4.83 | $ 1.04 | $ 7.37 | $ 16.71 | $ 23.92 | $ 27.12 |
| **Wells Drilled (net)** | | | | | | | | |
| Oil | **-** | - | - | - | 1.62 | 1.26 | - | 3.26 |
| Gas | **-** | - | - | 2.75 | 0.83 | 0.75 | - | 1.12 |
| Disposal/injection | **-** | - | - | - | - | 0.37 | - | - |
| Total wells drilled (net) | **-** | - | - | 2.75 | 2.45 | 2.38 | - | 4.38 |
| **FINANCIAL** *($ thousands, except per share amounts)* | | | | | | | | |
| Petroleum & natural gas revenues, net of royalties | **$ 9,000** | $ 10,527 | $ 14,934 | $ 15,240 | $ 24,065 | $ 25,972 | $ 32,595 | $ 36,029 |
| Funds from operations (1) | **$ 1,516** | $ 3,299 | $ 2,995 | $ 1,220 | $ 6,069 | $ 9,693 | $ 14,798 | $ 17,596 |
| Per share - basic & diluted ($/share) | **$ 0.01** | $ 0.02 | $ 0.01 | $ 0.01 | $ 0.03 | $ 0.05 | $ 0.07 | $ 0.08 |
| Net (loss) income from continuing operations (2) | **$ (5,303)** | $ (80,669) | $ (5,822) | $ 8,189 | $ (58,311) | $ 3,696 | $ 3,531 | $ 410 |
| Per share - basic & diluted ($/share) | **$ (0.02)** | $ (0.37) | $ (0.03) | $ 0.04 | $ (0.27) | $ 0.02 | $ 0.02 | $ - |
| Net (loss) income (2)(3)(4) | **$ (5,303)** | $ (80,669) | $ (5,822) | $ 8,189 | $ (60,348) | $ 11,472 | $ 4,391 | $ 6,085 |
| Per share - basic & diluted ($/share) | **$ (0.02)** | $ (0.37) | $ (0.03) | $ 0.04 | $ (0.28) | $ 0.05 | $ 0.02 | $ 0.03 |
| Capital expenditures | **$ 9,998** | $ 7,313 | $ 4,921 | $ 22,093 | $ 23,821 | $ 14,301 | $ 18,998 | $ 23,614 |
| Net debt (surplus) (1) (5) | **$ (29,614)** | $ (41,181) | $ (46,705) | $ (48,596) | $ (28,788) | $ (35,870) | $ 80,536 | $ 74,390 |
| Total assets (5) | **$ 321,564** | $ 333,036 | $ 414,280 | $ 431,085 | $ 434,318 | $ 472,241 | $ 589,515 | $ 604,419 |
| **Common Shares** (thousands) | | | | | | | | |
| Weighted average during period - basic | **215,337** | 215,274 | 215,089 | 215,083 | 215,081 | 214,895 | 214,226 | 214,188 |
| Weighted average during period - diluted | **215,337** | 215,274 | 215,089 | 215,112 | 215,081 | 216,773 | 215,814 | 214,245 |
| Outstanding at period end | **215,349** | 215,328 | 215,236 | 215,083 | 215,082 | 215,079 | 214,674 | 214,188 |

(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 $63.5 million and $75.0 million in impairment charges against properties for the three months ended December 31, 2014 and September 30, 2015, respectively.

(3) Quarters prior to and including December 31, 2014 include net income or loss from the Discontinued Operations.

(4) Significant crude oil production from the Discontinued Operations of 36,000 barrels was not sold at June 30, 2014.

(5) Quarters prior to the three months ended September 30, 2014 include the Discontinued Operations and their assets or working capital excluding marked-to-market derivative contracts, as applicable. Quarters subsequent to and including September 30, 2014, include a related Discontinued Operations payable balance.

### Factors That Have Caused Variations over the Quarters

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

Generally, our non-core property disposition program has resulted in a lower trend of natural gas and natural gas liquids production volumes. This trend was offset during the fourth quarter of 2014 when we began to realize continuous production from our drilling program and properties acquisition at Birley/Umbach. Offsetting this lower overall trend of natural gas and natural gas liquid volumes was crude oil production which has generally trended upwards resulting from the reinvestment of our non-core disposition proceeds into core area properties. However, during the first quarter of 2015, production volumes decreased reflecting the impact of significant dispositions in our Gilby and Karr areas and have since fallen in subsequent quarters due to voluntary shut-ins of properties with high operating costs/low netbacks and ongoing pipeline service restrictions and reduced system capacity. Our realized commodity prices and natural gas revenue, net of royalties have mostly trended with the Canadian Light Sweet and AECO benchmarks which generally increased until mid-2014 when they began to decrease with significantly lower benchmark pricing observed in the fourth quarter of 2014 and 2015. Changes in our petroleum and natural gas revenues, net of royalties and funds from operations have generally trended with benchmark commodity prices and volumes. Our net debt changed to a net surplus in the third quarter of 2014 with the repayment of our entire outstanding debt balance from the proceeds of the Discontinued Operations. The aforementioned Karr properties disposition increased our net surplus during the first quarter of 2015 after which our net surplus began to decrease as our capital expenditures exceeded our funds from operations. Our dispositions of non-core assets combined with funds from operations relative to capital expenditures, including business acquisitions, have allowed us to avoid having to raise proceeds through the issuance of our common shares.

Please refer to “Continuing Canadian Operations” and 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, 2015 and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out in our AIF are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally. If any of the these risks or other risks occur, our business, prospects, financial condition, results of operations and cash flows could be adversely affected in a material way.

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

### 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 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 to 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 participations 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 assure 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, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other 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 a 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 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 China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels 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 natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that 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 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 especially as certain reserves become 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. As a result, 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 natural 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 or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire space 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 as well as 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 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 and may decline in the near future 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, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, 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 acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the 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, 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.

## Risks Relating to Indemnification Rights

We are subject to risks relating to certain obligations guaranteed in favour of the buyer in connection with the Tunisian Disposition which was completed on August 19, 2014. We have guaranteed the payment of the indemnification obligations of 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 those of our company. 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 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, if disposed of, may realize less than their carrying value on our consolidated financial statements.

## 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 recourse 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. Any of these factors could materially adversely affect 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 over-runs 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 and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- 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.

## 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, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, 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. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also 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. Furthermore, 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 in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows.

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.

## Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the 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. 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, methods, 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 oil 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. 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 adversely affected in a material way. If we are unable to utilize the most advanced commercially available technology, 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 other 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. See “Industry Conditions” in our 2016 AIF. 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. 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 to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

## 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 will take effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before March 31, 2016.

## 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 laws 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, Saskatchewan 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 becomes defunct. 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 of the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. 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 as they may be disproportionately affected by price instability.

## Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases and 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 will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets are not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada is expected to announce a plan to further reduce its GHG emission reduction targets by March 11, 2016. 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. 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;
- commodity prices;
- our credit rating (if applicable);
- 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 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.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in our revenues from our reserves, which may 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 amount authorized under the Revolving Term Credit Facility is dependent on the borrowing base determined by the lenders. We are required to comply with covenants under our Revolving Term Credit Facility which include, certain financial ratio test and certain revenue and expenditure (including debt service) coverage ratio tests and, which may, from time to time, either affect the availability, or price, of existing and/or additional funding under the Revolving Term 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 and coverage ratio tests) could result in default under the Revolving Term Credit Facility which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under the Revolving Term Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Revolving Term 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 lenders use 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 year and a half, our borrowing base was reduced in June and December 2015. 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 Revolving Term Credit Facility. This could result in the requirement to repay a portion, or all, of our indebtedness.

If the our lenders require repayment of all or portion of the amounts outstanding under the Revolving Term 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 Revolving Term 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 Revolving Term Credit Facility, the lenders under the Revolving Term Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The Revolving Term 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 organizations. 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 the 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) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment 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 an unforeseen defect in the chain of title will not arise. Our actual interest in our 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 we receive.

## 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 are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were 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 37.4% 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 our company, 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 our minority shareholders and without providing for a purchase of such shareholders' shares. Accordingly, the common shares held by our 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 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 our financial condition, the need for funds to finance ongoing operations and other considerations, as our Board of Directors considers relevant.

## 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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of 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.

## 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.

## 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 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. In addition, 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. 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) (“ABCA”) 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 ABCA.

## 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 person insurance in effect for us. 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.

## 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 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 indicators

Judgments are required to assess when impairment indicators exist and impairment 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, 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 various 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.

## Foreign currency

Prior to the August 19, 2014 sale of the Discontinued Operations pursuant to the PSA, SVI Barbados and its wholly-owned subsidiary's functional currency required assessing several factors, including the dominant currency used in transactions such as the settlement of revenues and operational and capital expenditures.

# New Accounting Standards and Amendments

## 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.

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 may affect the amount and/or timing of revenue recognized.

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 goal of the standard is to bring leases on the balance sheet 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, 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, and follows the criteria set out in IAS 17. As of January 1, 2019, we will be required to adopt this standard.

Management is evaluating the impact these standards may have on our financial statements.

# Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to us is made known to our CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of our disclosure controls and procedures at December 31, 2015 and have concluded that our disclosure controls and procedures are effective at December 31, 2015.

# 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. No material changes in our internal controls over financial reporting were identified during the period beginning on October 1, 2015 and ended on December 31, 2015, that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting. 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, 2015 and have concluded that our internal controls over financial reporting are effective at December 31, 2015.

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 from operations is calculated from cash flow from Continuing Canadian Operations adjusted for changes in non-cash working capital related to Continuing Canadian Operations, exploration and evaluation expenses related to Continuing Canadian Operations and decommissioning obligation expenditures related to Continuing Canadian Operations. This term does not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies. Management believes that funds from operations is a key measure to assess our ability to finance capital expenditures and when debt is drawn, debt repayments. Funds 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.
- Net debt (surplus) is calculated as bank debt adjusted for working capital excluding mark-to-market derivative contracts, current portion of decommissioning obligation and assets and liabilities held for sale. Working capital excluding mark-to-market derivative contracts, current portion of decommissioning obligation and assets and liabilities held for sale is calculated as current assets less current liabilities as they appear on the balance sheets, excluding derivative contracts, assets and liabilities held for sale and the current portion of both debt and decommissioning obligations. Management uses net debt (surplus) to assist us in understanding our liquidity at specific points in time.
- 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.
- Net production and operating expense is calculated as production and operating expense less processing and gathering revenues. Management uses net production and operating expense to determine the current period's 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: the amount of our 2016 capital program, our forecasted production for the year ended 2016, how our 2016 capital program is anticipated to be funded, that we will not be taxable in the near term, that we will not be required to payout on indemnification to the buyer of the Discontinued Operations in excess of amounts already accrued, expectations regarding future reductions in operating and G&A costs, future exploration and development activities and the timing thereof and how we intend to manage our company during 2016 as well as our expectations regarding production and capital expenditures set out in the table under the heading "Outlook".

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 past operations, 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 of 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 commodity price and cost assumptions, the results of negotiations and the plans of our partners in certain of our areas; that the budgeted amounts and expenditures set forth herein, which are subject to the discretion of our Board of Directors, will not be amended in the future and the continued availability of adequate cash, 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 2016 capital program based on its discretion; environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increased 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.

## Barrels of Oil Equivalent

Barrels of oil equivalent (boe) is calculated using the conversion factor of 6 mcf (thousand cubic feet) of natural gas being equivalent to one barrel of oil. Boe’s may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl (barrel) 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.

## Future Oriented Financial Information

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