Q1 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 three months ended March 31, 2015 and 2014 and should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes as at and for the three months ended March 31, 2015 and 2014 (the "Interim Financial Statements") and our audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2014 and 2013 (the "Annual Financial Statements"). This MD&A is based on information available as at May 11, 2015.

The term "first quarter" or similar terms are used throughout this document and refer to the three months ended March 31, 2015. The terms "same quarter of 2014" and "comparative period" or similar terms are used throughout this document and refer to the three months ended March 31, 2014. The term "2014" or similar terms are used throughout this document and refer to the year ended December 31, 2014.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2014 ("AIF"), can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The Interim Financial Statements have been prepared in accordance with International Accounting Standard 34 'Interim Financial Reporting' using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board. They include the accounts of our direct subsidiaries all of which are wholly owned. As discussed in the "Discontinued Operations" section of this MD&A, the comparative period'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 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 and per boe), netback, net debt (surplus) and net production expense (and per boe), 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. 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 ("SVI (BVI)"), completed a sale transaction comprising 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 have been presented as Discontinued Operations for the comparative period in the Interim 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.

Forward-Looking Information

Statements throughout this MD&A that are not historical facts may be considered "forward-looking statements". Readers should read the advisory under the heading "Forward-Looking Statements" in this MD&A.

Financial and Operating Highlights

Three months ended March 31		2015		2014
CONTINUING CANADIAN OPERATIONS (1) (2)				
Production				
Crude oil (bbl/d)		**1,485**		2,084
Natural gas liquids (boe/d)		**682**		950
Natural gas (mcf/d)		**33,007**		29,364
Average daily production (boe/d)		**7,668**		7,928
Sales Prices				
Average oil price ($/bbl)	**$**	**49.03**	$	96.41
Average natural gas liquids price ($/boe)	**$**	**36.47**	$	74.10
Average natural gas price ($/mcf)	**$**	**2.65**	$	6.01
Netback (3)				
Average commodity pricing ($/boe)	**$**	**24.15**	$	56.50
Royalties ($/boe)	**$**	**(2.07)**	$	(6.01)
Net production expenses ($/boe) (3)	**$**	**(17.04)**	$	(16.91)
G&A expense ($/boe)	**$**	**(4.00)**	$	(6.46)
Netback ($/boe) (3)	**$**	**1.04**	$	27.12
Wells Drilled (net)				
Oil		**-**		3.26
Gas		**2.75**		1.12
Total wells drilled (net)		**2.75**		4.38
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$**	**15,240**	$	36,029
Funds from operations (3)	**$**	**1,220**	$	17,596
Per share - basic and diluted ($/share)	**$**	**0.01**	$	0.08
Net income from continuing operations	**$**	**8,189**	$	410
Per share - basic and diluted ($/share)	**$**	**0.04**	$	-
Net income (4)	**$**	**8,189**	$	6,085
Per share - basic and diluted ($/share)	**$**	**0.04**	$	0.03
Capital expenditures	**$**	**22,093**	$	23,614
Net debt (surplus) (3) (5)	**$**	**(48,596)**	$	74,390
Total assets (4)	**$**	**431,085**	$	604,419
Common Shares (thousands)				
Weighted average during period				
- basic		**215,083**		214,188
- diluted		**215,112**		214,245
Outstanding at period end		**215,083**		214,188

(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) Funds from operations, funds from operations per share, net debt (surplus), netback and net production expense are non-IFRS measures as defined throughout this MD&A. These terms 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.

(4) The comparative period includes the Discontinued Operations' net income or assets, as applicable.

(5) The comparative period includes the Discontinued Operations' working capital excluding marked-to-market derivative contracts.

Continuing Canadian Operations

Petroleum and Natural Gas Production Volumes

Three months ended March 31	2015	2014
Crude oil (bbl/d)	**1,485**	2,084
Natural gas liquids (boe/d)	**682**	950
Natural gas (mcf/d)	**33,007**	29,364
Total (boe/d)	**7,668**	7,928

Total Production Volumes

Our production volumes for the first quarter had a modest decrease of 260 boe/d, or three percent, compared to the same quarter of 2014. This decrease resulted from both the first quarter and 2014 dispositions of producing properties with associated production of 1,450 boe/d. To date we have shut-in approximately 550 boe/d of production in response to lower commodity prices. This resulted in a decrease in production during the first quarter of approximately 300 boe/d. Partially offsetting this first quarter decrease was 1,100 boe/d of production from our 2014 and 2015 winter drilling programs that were focused on Montney and Dunvegan light crude oil in Grande Prairie, Alberta and Montney liquids rich natural gas on our Birley/Umbach, BC properties. Late in 2014, we also acquired a 1,200 boe/d natural gas property in the Birley/Umbach area. This 100% and owned operated acquisition included key infrastructure which we believe strategic to the long term delivery of volumes from this area.

During the first quarter we drilled three (2.75 net) wells in the Birley/Umbach area, of which one (0.75 net) was completed and brought on production on March 26, 2015 at a rate of 815 boe/d (21% liquids) over the first 30 days and is currently producing at 625 boe/d (16% liquids). However, as a result of reaching capacity at our owned and operated nine mmcf/d compression facility, bringing this well on production required us to shut-in the first (0.75 net) of the two horizontal wells (1.50 net) we drilled in the Birley/Umbach area. In the absence of expanding our facility in response to improved commodity pricing, we will maintain its current capacity throughput by layering on volumes from this standing well to offset any declines from the other two producing wells.

Given the recent decreases in commodity prices, we have been carefully assessing our capital program and have delayed the completion of three (2.75 net) wells in our Birley/Umbach area, the expansion of the previously mentioned compression facility and the drilling of a Montney light crude oil well in Gold Creek pending the recovery of commodity prices and decreases in third party drilling and completion costs. These measures will help to maximize shareholder value through an increase in funds from operations by matching the comparatively higher initial production rates with higher pricing, while also taking advantage of lower completion costs.

Natural Gas and Natural Gas Liquids Production (“NGL”) Volumes

Natural gas production for the first quarter increased compared to the same quarter of 2014. This increase resulted from 10,700 mcf/d of natural gas production associated with both last year’s property acquisition and our successful drilling program in the Birley/Umbach area. Partially offsetting this increase was last year’s disposition of the predominantly natural gas and associated liquids’ properties in the Gilby area with associated production of approximately 800 boe/d. As mentioned, we have voluntarily shut-in approximately 550 boe/d of production, which includes natural gas production. As a result of the disposition of the Gilby properties and capacity constraints on our Montney liquids rich play we are reporting a first quarter decrease in NGL production of 268 boe/d compared to the same quarter of 2014.

Crude Oil Production Volumes

Our crude oil production volumes for the first quarter decreased by 599 bbl/d compared to the same quarter of 2014. This decrease resulted from the sale of producing properties in the Karr area of Alberta, which closed on January 6, 2015, for net proceeds of $41.1 million. These sold properties had associated production of approximately 485 boe/d at their time of sale and 633 boe/d during the comparative quarter of 2014. Also causing this decrease was crude oil production associated with last year’s dispositions including our former Boundary Lake properties. Partially offsetting the decrease 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. The production from our first horizontal Montney oil well (0.37 net) at Gold Creek has averaged gross production of over 250 bbl/d of crude oil and 3,300 mcf/d of natural gas during its first 120 days of production. However, this well was shut-in for a portion of the first quarter while we waited for approval of a water disposal application. Our second Montney horizontal well, drilled 20 kilometres west of the first well in November 2014, tested 875 boe/d and should be on production late in 2015 or in the first half of 2016. At our Albright/Beaverlodge property, our non-operated horizontal Dunvegan oil well (0.5 net) that was brought on production in December 2014 averaged a gross 177 boe/d (88% crude oil) over its first 141 days.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended March 31		**2015**		2014
($ thousands, except per unit amounts)				
Oil sales	**$**	**6,553**	$	18,087
$/bbl		**49.03**		96.41
Natural gas liquids sales	**$**	**2,238**	$	6,333
$/boe		**36.47**		74.10
Natural gas sales	**$**	**7,877**	$	15,894
$/mcf		**2.65**		6.01
Petroleum and natural gas revenue	**$**	**16,668**	$	40,314
$/boe		**24.15**		56.50

Our petroleum and natural gas revenues of $16.7 million during the first quarter decreased compared to the same quarter of 2014. This decrease was caused by both lower realized commodity pricing and a decrease in petroleum sales volumes. The decrease in our realized commodity pricing was mostly due to lower benchmarks pricing which substantially began their decline during the fourth quarter of 2014. Our ratio of the comparatively higher priced crude oil sales, relative to total sales volumes, decreased to 19% during the first quarter compared to 26% in the same quarter of 2014, further contributing to a lower realized weighted average commodity price. This decreased ratio was the result of the relatively “oily” Karr properties disposition in combination with the 2014 acquisition of natural gas weighted properties.

Benchmark Prices

Three months ended March 31		**2015**		2014
Crude oil Canadian light sweet (1) ($/bbl)	**$**	**53.22**	$	99.79
Natural gas liquids WTI (2) ($US/bbl)	**$**	**48.63**	$	98.68
Natural gas AECO gas (3) ($/mcf)	**$**	**2.79**	$	5.80

(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 first quarter, as did our average realized crude oil price, compared to the same quarter of 2014. Our crude oil quality remained relatively consistent for the first quarter as compared to the same quarter of 2014.

Natural Gas Liquids 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 first quarter, and consistent with the decrease in the Canadian light sweet oil benchmark, our realized NGL price of $36.47/boe decreased compared to $74.10/boe for the same quarter of 2014. The ratio of our NGL price relative to Canadian light sweet oil was 69% and 74% for the first and comparative quarters, respectively. The decrease in this ratio was due to a lower average price for propane which fell 89% from the comparative quarter of 2014 to the first quarter. This price decrease resulted from an industry oversupply. The effect of this decreased propane price on our weighted average NGL price overshadowed the impact of an increased ratio of condensates. This increase resulted from our new production at Birley/Umbach and the sale of our Gilby properties, whose liquids production had a relatively lower heat equivalent value.

Natural Gas Pricing

Our realized natural gas price of $2.65/mcf for the first quarter decreased from $6.01/mcf for the same quarter of 2014. This decrease was due to a lower AECO benchmark. We also had higher natural gas production in BC from our prior year's development and properties acquisition in our Birley/Umbach area. During the first quarter, a portion of this natural gas production was sold at the BC Station 2 ("Stn2") and Alberta Gas Plant spot prices which experienced pricing volatility. The Alberta Gas Plant spot pricing volatility was a consequence of a third party pipeline restriction resulting from a service outage which forced us and other producers who had firm delivery volumes to divert their production to another third party pipeline. This divergence of production onto the other third party pipeline resulted in it reaching capacity which in turn forced upstream BC natural gas production, including a portion of our own, to be delivered and sold at the Stn2 spot price. The resulting oversupply of natural gas being delivered to the Stn2 market caused larger differentials than previously observed relative to AECO. The third party pipelines still have service outages so we anticipate continued Alberta Gas Plant and Stn2 spot pricing volatility.

Royalties

Three months ended March 31	**2015**	2014
($ thousands, except where noted)		
Royalties	**$ 1,428**	$ 4,285
Per sales ($/boe)	**$ 2.07**	$ 6.01
Percent of revenues (%)	**9**	11

For the first quarter our royalties decreased on an overall basis, per boe and as a percentage of revenue, compared to the same quarter of 2014. The decrease overall and on a boe basis resulted from a lower realized price as compared to the same quarter of 2014. As consequence of the volatile Stn2 spot prices that we received on a portion of our BC natural gas production, part of the BC crown royalties charged were less than its fixed producer cost of service credit. When this credit was combined with an increase in the proportion of natural gas sales volumes with its relatively lower associated royalty rate, the effect was a decrease in royalties as a percentage of revenue in the first quarter compared to the same quarter of 2014.

Commodity Price Risk Management Contracts

To help mitigate commodity price risk, we enter into financial derivative contracts which 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 financing techniques.

Our unsettled swap commodity price derivative contract is reported at its approximated fair value on the date of the Interim 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 contract as compared to our received price multiplied by the remaining notional volumes. Volatility in the commodity price and any decrease in the remaining notional volumes will result in changes in the fair value of our derivative contract from one period to the next. The change in the fair values between reporting periods are recognized in net income as unrealized gains or losses on derivative contracts. Realized gains or losses on the derivative contracts are recognized in net income on the unwinding of the financial derivative contract term. For the first quarters of 2015 and 2014, we reported the following realized gains and losses and unrealized losses on our derivative contracts:

Three months ended March 31	**2015**	2014
($ thousands)		
Realized (gains) losses on derivative contracts	**$ (300)**	$ 1,174
Unrealized losses on derivative contracts	**284**	3,761
Total	**$ (16)**	$ 4,935

During the first quarter we realized a gain on our AECO derivative contract as this benchmark was lower than our received fixed price of $3.50/GJ. If we had included this settlement in our natural gas revenues, we would have reported an adjusted natural gas sales price for the first quarter of $2.76/mcf compared to our reported price of $2.65/mcf.

Our unrealized loss for the first quarter resulted from the unwinding of the AECO derivative contract over its term as its unrealized fair value became realized. As at March 31, 2015, this commodity price contract had an estimated current asset fair value of $1.2 million with the following terms:

Indexed Price	Notional Volumes	Company's Received Price	Remaining Contractual Term
AECO	5,000 GJ/d	$3.50/GJ	April 1, 2015 to December 31, 2015

Based on our revised guidance, this price risk contract is expected to secure our received commodity prices on approximately 17% of natural gas sales volumes during the year ended 2015.

Production and Operating Expense

Three months ended March 31		2015		2014
($ thousands, except where noted)				
Production & operating	$	12,830	$	13,381
Less:				
Processing & gathering revenues		(1,070)		(1,318)
Net production & operating expense (1)	$	11,760	$	12,063
Per sales net production & operating expenses ($/boe) (1)	$	17.04	$	16.91
Per sales production & operating expenses ($/boe)	$	18.59	$	18.75

(1) Net production and operating expense and net production and operating expense per boe are non-IFRS measures and are calculated as production and operating expense less processing and gathering revenues. Management uses the net production and operating expense non-IFRS measure to determine the current period's cash cost of operating expenses and the net production and operating expense per boe is used to measure operating efficiency on a comparative basis. These terms 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.

The first quarter's production and operating expense in total and on a boe basis of $12.8 million and $18.59/boe decreased compared to the same quarter of 2014. These decreases resulted from the recent disposition of properties at Gilby and Karr, the voluntary shut-in of relatively higher operating cost/lower netback wells and other implemented cost saving initiatives. The effect of the per boe decrease is most notable when compared to our reported fourth quarter of 2014 operating costs of $19.96/boe. This comparison shows that this respective measure decreased during the first quarter by $1.37/boe.

During the first quarter, our voluntary shut-in of lower netback wells totalled approximately 300 boe/d. Early in the second quarter of 2015, in response to decreased commodity prices, we voluntarily shut-in additional higher operating cost/lower netback wells. These wells are mostly located on our Pouce Coupe, Marten Hills, Rainbow, Enchant and Rigel properties. Had these properties been shut-in at the beginning of the first quarter, and ignoring the effect of one-time shut-in costs, our reported production & operating costs in total and on a boe basis for the first quarter would have been $11.7 million and $17.49/boe, respectively, with only a 250 boe/d decrease in our reported production volumes.

Partially offsetting the first quarter's decreases in production and operating costs in total and on a boe basis, relative to the comparative quarter, were higher production costs associated with our recent development of Montney petroleum and Dunvegan light crude oil and last year's development and properties acquisition in our Birley/Umbach area. For these core area developments, more oil, water and emulsion hauling, emulsion processing, road maintenance, winter access and water disposal costs coupled with increased demand for some of these services contributed to these increases.

At our Montney prospect located at Gold Creek, the first quarter's production and operating costs on a boe basis were also affected by continued third party pipeline and facility capacity constraints in the Grande Prairie area. We shut-in this prospect during March to avoid the relatively high water hauling and disposal costs. Late in the first quarter, we received formal approval of our water disposal application. As a result, we recommenced production from this prospect and began to dispose of the associated water down a well that was drilled in the third quarter of 2014. This is expected to significantly reduce the relatively higher operating costs caused by trucking and disposing of the water associated with production from our first mid-Montney horizontal well in this area and to improve the economics of follow-up wells.

At our Birley/Umbach area we added liquids rich natural gas sales volumes from recent drilling successes in addition to natural gas volumes from last year's acquisition. These added sales volumes also increased our first quarter's operating costs in total and on a boe basis compared to the same quarter of 2014. For the first quarter, we also incurred one-time increased field staff costs as we replaced certain positions in addition to cathodic and calibration services. After the planned future expansion of the compression facility in this area, we expect decreases in both our operating costs overall and on a boe basis as implemented cost saving initiatives take effect and sales volumes from a standing well and another three drilled wells that are still to be completed are brought on-stream.

In response to the recent decline in commodity pricing we are targeting significant cost reductions and have forecasted production and operating costs for the year ended 2015 of between $41 million and $43 million. We are enroute to achieving 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.

Processing and gathering revenue decreased during the first quarter compared to the same quarter of 2014. The sale of the Gilby area properties during the fourth quarter of 2014 included certain processing facilities and distribution pipelines. This sale resulted in lower processing and gathering revenues in the first quarter.

General & Administrative ("G&A") Expense

Three months ended March 31	**2015**	2014
($ thousands, except per unit amounts)		
G&A expense	**$ 2,761**	$ 4,621
Per sales ($/boe)	**$ 4.00**	$ 6.46

G&A expense on an overall and boe basis decreased for the first quarter compared to the same quarter of 2014. These decreases were achieved despite incurring $0.4 million in severance costs during the first quarter from staffing reductions. Removing the effect of these non-reoccurring severance costs resulted in a first quarter G&A expense of $2.3 million or $3.38/boe.

During the first quarter, as a result of the previously announced decreased expenditures for our 2015 capital program, we continued to evaluate our G&A cost structure and consequently reduced our staffing and consultant levels in addition to implementing other cost saving initiatives. For the first quarter, this resulted in our G&A expense decreasing overall and per boe compared to the same quarter of 2014. Compared to the first quarter, once the full effect of these reductions are realized we expect to report materially lower G&A costs for the future quarters of 2015. Also during the first quarter, our G&A decreased due to a higher related party recovery for an additional $0.3 million. During 2015, we expect this related party recovery increase to be maintained. In the comparative quarter we also reported an additional $0.8 million of incentive compensation. Finally, we achieved a decrease in G&A on a boe basis despite lower production volumes. We will continue to evaluate our existing G&A cost structure and implement cost savings initiatives throughout 2015, including a planned temporary reduction in our work week which we anticipate will save us a combined $0.5 million during the second and third quarters. We anticipate meeting our forecasted G&A costs for the year ended 2015 of between $10.5 million and $11.0 million.

Netback

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

Three months ended March 31	**2015**	2014
Per sales ($/boe)		
Realized sales price	**$ 24.15**	$ 56.50
Less:		
Royalties	**(2.07)**	(6.01)
Net production expense (2)	**(17.04)**	(16.91)
G&A expense	**(4.00)**	(6.46)
Netback (1)	**$ 1.04**	$ 27.12

(1) Netback is a non-IFRS measure and 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-IFRS 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.

(2) See the production and operating expense table where this non-IFRS measure is defined.

The netback for the first quarter significantly decreased compared to the same quarter of 2014. This decrease resulted from lower commodity benchmark prices. Also contributing to this decrease was a lower proportion of crude oil sales volumes relative to total sales volumes. Despite our first quarter realized crude oil price being essentially one-half of what it was for the comparative quarter, we still receive a higher price per barrel on our crude oil sales than we do on an equivalent boe of natural gas. The decrease in the proportion of crude oil sales resulted from the disposition of "oily" producing properties in the Karr area of Grande Prairie and higher natural gas production from our Birley/Umbach area. The netback decrease was partially offset by lower royalties and G&A on a boe basis. For the same reasons our realized price decreased, we are reporting lower royalties on a boe basis. The decrease in G&A expenses on a boe basis resulted from staffing and consulting headcount reductions, an increase in a recovery from a related party and other cost saving initiatives. As mentioned, we continue to work to lower operating and G&A costs. We will continue to strive to implement cost saving initiatives throughout 2015 to reduce these costs.

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

Three months ended March 31	**2015**	2014
($ thousands, except per unit amounts)		
Depletion, depreciation and amortization	**$ 10,507**	$ 12,287
Per sales ($/boe)	**$ 15.22**	$ 17.22

DD&A expense decreased during the first quarter as a result of the lower depletion rate and production volumes when compared to the same quarter of 2014. The decrease in our overall depletion rate is due to the impact from the lower carrying amounts of our development and production assets ("D&P Assets") resulting from last year's reported impairment charge of $63.5 million and the lower rate we are observing on our Birley/Umbach properties. In addition, our overall depletion rate decreased as a result of the disposition of the Karr producing properties with their higher associated rate. The decreases in the rate and in total are partially offset by the higher amortization associated with 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.

Impairment of Development and Production Assets

We are not reporting an impairment charge for the first quarter. For our D&P Assets as at March 31, 2015, we assessed whether there were any triggers indicating impairment of these assets. During the first quarter, we noted that both spot and forward petroleum and natural gas prices used by our independent reserve engineer had decreased relative to price points at December 31, 2014. Since then, WTI has recovered to approximately US$60/bbl. We last recognized impairment of $63.5 million on our D&P Assets for the year ended December 31, 2014, using a measure of value-in-use. Given consideration in the assessment of that measure were various petroleum and natural gas forward prices. Drilling results for the first quarter have not provided any additional information which would challenge our previous assumptions included in our December 31, 2014 measure of value-in-use. Finally, we are starting to observe pricing concessions from third party vendors which should decrease our future development and operating costs. Based on these facts, and given lower petroleum and natural gas prices have yet to be sustained over a more substantial period of time, we determined that as at March 31, 2015, there was no overall trigger indicating impairment of our D&P Assets.

Gains on Disposition of Properties

On January 6, 2015, we completed the sale of certain petroleum and natural gas properties including undeveloped lands located in the Karr area of northwestern Alberta and other negligible properties for net proceeds of $41.7 million. 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. The net carrying amounts of these sold properties and undeveloped lands was less than the sales proceeds and purchase price adjustments resulting in a first quarter gain of $19.4 million.

Share-Based Compensation

Three months ended March 31		2015		2014
($ thousands)				
Share-based compensation	$	426	$	194

For the first quarter, share-based compensation increased as a result of amortizing the fair value related to the restricted and performance awards which were granted for the first time during the second quarter of 2014 with additional minor grants during the second half of the comparative year. Also, this increase in share-based compensation includes amortizing the fair value of share options granted subsequent to the first quarter of 2014.

Bad Debt Expense

Three months ended March 31		2015		2014
($ thousands)				
Bad debt expense	$	497	$	20

In an effort to manage our credit risk we continuously monitor and assess the collectability of our purchaser and joint venture partners' receivables in addition to our other receivable positions. For our first quarter reporting, we identified joint venture partners that filed for creditor protection. As a result, for the first quarter we provided for $0.5 million of joint venture partner receivables that were deemed uncollectible.

Foreign Exchange Gains & Other

Three months ended March 31		2015		2014
($ thousands)				
Foreign exchange gains and other	$	(460)	$	(162)

During the first quarter we recognized foreign exchange gains from holding US$4.8 million as a natural hedge to the expected $2.8 million of US dollar denominated indemnifications we provided to the buyer of the Discontinued Operations.

Financing Expenses

Three months ended March 31		2015		2014
($ thousands)				
Interest and financing (income) charges	$	(131)	$	710
Amortization of deferred financing costs		-		74
Accretion of decommissioning obligation		617		672
Total	$	486	$	1,456

We reported interest and financing income for the first quarter as the interest earned on our average cash deposits, which were $60.3 million on March 31, 2015, more than offset the standby fees we incurred on the $125.0 million fully available credit facility. The interest income we are currently receiving on our bank accounts is competitive to other short-term liquid investments. During the comparative quarter, we incurred interest expense on the $78.5 million outstanding credit facility balance in addition to standby fees on the available balance. During the third quarter of 2014, we repaid the outstanding credit facility balance using the proceeds from the sale of the Discontinued Operations. In conjunction with this repayment, we expensed the remaining deferred financing costs.

The accretion charge during the first quarter had a modest decrease compared to the same quarter of 2014. This decrease resulted from applying a lower discount rate when accounting for the passage of time related to the decommissioning obligation.

Net and Comprehensive Income

Three months ended March 31		2015		2014
($ thousands, except where noted)				
Weighted average shares outstanding - basic (thousands)		**215,083**		214,188
Dilutive impact of share options (thousands)		**29**		57
Weighted average shares outstanding - diluted (thousands)		**215,112**		214,245
Net income from continuing operations	**$**	**8,189**	$	410
Per share - basic & diluted ($/share)	**$**	**0.04**	$	-
Net income from discontinued operations	**$**	**-**	$	5,675
Per share - basic & diluted ($/share)	**$**	**-**	$	0.03
Net income	**$**	**8,189**	$	6,085
Per share - basic & diluted ($/share)	**$**	**0.04**	$	0.03
Comprehensive income	**$**	**8,189**	$	10,827
Per share - basic and diluted ($/share)	**$**	**0.04**	$	0.05

Our first quarter net income from continuing operations of $8.2 million increased relative to the same quarter of 2014. This increase resulted from a gain of $19.4 million related to our property dispositions and lower charges for operating, G&A and depletion. This increase was also caused by recoveries from a derivative contract and financing income compared to charges for both of these in the same quarter of 2014. Partially offsetting the increase in net income from continuing operations were lower petroleum and natural gas revenues resulting from both lower petroleum sales volumes and a decrease in our realized commodity prices.

Our net income for the comparative period also included the financial results from our Discontinued Operations. In addition to including net income, our comprehensive income for the comparative period also included a foreign exchange gain on the translation of the US dollar denominated Discontinued Operations as reported in Canadian dollars. As previously mentioned, our Discontinued Operations were sold on August 19, 2014.

Capital Resources, Capital Expenditures and Liquidity

On January 19, 2015, we announced that our Board of Directors had approved a reduced 2015 capital program of $44.5 million focused on further delineating our Montney resource at Birley/Umbach, BC and Gold Creek, Alberta at a pace that does not impair its value or growth potential. At March 31, 2015, we were approximately half way through this program. Given that commodity pricing has yet to significantly improve, we are now considering deferring the second half of our program that includes a facility installation and our drilling and completions program. By limiting the new wells that we bring on production in the current weak commodity price environment, we are not compromising our most economic rates of return. We will continue to closely monitor the second half of our reduced 2015 capital program and will adjust it accordingly in response to changing commodity prices and to take advantage of strategic growth opportunities that may present themselves as a result of the current industry environment.

For the first quarter, we financed our investment in capital, decommissioning, exploration and evaluation expenditures and non-cash working capital from cash on deposit, funds from operations and proceeds from the sale of the Karr properties. Although we are contemplating further reducing our remaining 2015 capital program, if we were to spend the second half of this program, we will be able to finance it through our existing net surplus position which included $60.3 million of cash on hand at March 31, 2015.

Funds from Operations

The following table outlines the calculation of our funds from operations[1]:

Three months ended March 31	2015	2014
($ thousands, except where noted)		
Cash flow from continuing operating activities	$ 639	$ 12,190
Add back:		
Change in operating non-cash working capital	128	4,816
Provision expenditures	453	590
Funds from operations [1]	$ 1,220	$ 17,596
Per share - basic and diluted [1]	$ 0.01	$ 0.08
Per sales ($/boe) [1]	$ 1.77	$ 24.66

(1) Funds from operations, funds from operations per share and funds from operations per boe are non-IFRS measures. Funds from operations is calculated from cash flow from continuing operations adjusted for changes in non-cash working capital related to continuing operations and decommissioning obligation expenditures related to continuing operations. Funds from operations per share or per boe is calculated from funds from operations as previously defined divided by the weighted average basic and diluted shares outstanding during the period or sales volumes, respectively. Funds flow from operations does not include the results of the Discontinued Operations. Management believes that funds from operations is a key measure to assess our ability to finance capital expenditures and debt repayments. Funds from operations as presented 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 cash flow from operations.

During the first quarter, our funds from operations significantly decreased to $1.2 million compared to $17.6 million in the same quarter of 2014. This decrease was due to a considerably lower netback and a decrease in petroleum sales volumes. The decrease in the netback resulted from significantly lower benchmark prices. The magnitude of the decrease was also exaggerated by the comparative quarter's average natural gas price of $6.01/mcf, which was the highest quarterly natural gas realized price we have observed since we began operating under the name Chinook Energy Inc. The decrease in the petroleum sales volumes resulted from the Karr and Gilby property dispositions coupled with capacity constraints at our Montney liquids rich development. Partially offsetting these decreases were lower costs and a realized gain from our derivative contract. The most notable cost decreases were for G&A and cash financing charges. G&A costs decreased $1.9 million due to headcount reductions of both personnel and consultants, implemented cost saving initiatives, lower incentive compensation and a higher related party recovery. Cash finance income in the first quarter from cash on deposit resulted in an increase in funds from operations of $0.8 million compared to the first quarter of 2014 when we had outstanding debt with associated interest charges. We also had a realized gain for the first quarter from our derivative contract which increased funds from operations by $1.5 million compared to losses on similar contracts for the same quarter of 2014. As a result of the cash finance income and the realized gain on our derivative contract falling "below-the-line", on a boe basis we reported higher funds from operations than our netback for the first quarter.

Credit Facility

	March 31 2015	December 31 2014
($ thousands)		
Long-term debt	$ -	$ -
Less:		
Working capital excluding mark-to-market derivative contracts and assets and liabilities held for sale [1]	(48,596)	(28,788)
Net debt (surplus) [1]	$ (48,596)	$ (28,788)

(1) Net debt (surplus) and working capital excluding mark-to-market derivate contracts and assets and liabilities held for sale are non-IFRS measures. Net debt (surplus) is calculated as bank debt adjusted for working capital excluding mark-to-market derivative contracts and assets and liabilities held for sale. Working capital excluding mark-to-market derivative contracts and assets and liabilities held for sale is calculated as current assets less current liabilities both of which exclude derivative contracts and assets and liabilities held for sale and current liabilities excludes the current portion of debt. Management uses net debt (surplus) to assist us in understanding our liquidity at specific points in time. Mark-to-market derivative contracts are excluded from working capital, in addition to net debt (surplus), as management intends to hold each contract through to maturity of the contract's term as opposed to liquidating each contract's fair value or loss.

We remained undrawn on our credit facility at March 31, 2015. We had a net surplus of $48.6 million at March 31, 2015, compared to $28.8 million at December 31, 2014. This positive change of $19.8 million was due to the proceeds of $41.7 million received mostly from the Karr property disposition and $1.2 million from funds from operations which excluded $0.5 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 $23.7 million.

As at March 31, 2015 and December 31, 2014, we had access to an undrawn revolving credit facility with a maximum availability of $125.0 million. The available credit from this facility at March 31, 2015 was unchanged from December 31, 2014, at $124.7 million. We have an outstanding letter of credit of $0.3 million as secured by our lending syndicate which reduces the available credit from the maximum available. On or before June 25, 2015, this facility's revolving period and availability will be redetermined using our independent reserve engineer's reserve estimates as at December 31, 2014. The availability of our credit facility may be revised at that time.

Capital Expenditures

Capital expenditures were as follows:

Three months ended March 31		**2015**		2014
($ thousands)				
Land and lease	**$**	**112**	$	161
Drilling and completions		**11,671**		18,443
Facilities and equipment		**10,005**		4,456
Field expenditures		**21,788**		23,060
Capitalized G&A		**299**		260
Furniture and equipment		**6**		294
Total	**$**	**22,093**	$	23,614
Proceeds from dispositions	**$**	**41,734**	$	-

During the first quarter we drilled three (2.75 net) horizontal Montney gas wells, on our Birley/Umbach property in northeastern BC, one (0.75 net) of which was completed, tested and brought on production in late March 2015. The average gross production from this newly completed well was 815 boe/d (21% liquids) during its first 30 days of production.

We now have a total of six (5.0 net) horizontal Montney wells drilled on the Birley/Umbach property, delineating a significant portion of our 65 section land base in the area. Three (2.25 net) of these wells have been completed and are tied-in to production facilities. Due to restrictions at our owned and operated compression facility, which limit raw gas throughput to nine mmcf/d, we are currently only able to produce two of these wells at a time and will layer in volumes from the third well as natural declines begin to occur. All equipment needed to expand that facility to 35 mmcf/d of throughput capacity has been purchased and/or fabricated and is ready to install. We also built a 1.6 kilometre 12 inch gathering line during the first quarter from our gas compression facility to a nearby drilling pad with three drilled horizontal wells, one of which had been previously completed. Completion of the two remaining wells and a third standing well are dependent on the expansion of the compression facility in addition to a combination of improvement in commodity pricing and expected costs as we move into the second half of 2015.

We plan to drill one additional Montney well in Gold Creek in the second half of 2015, subject to our assessment of commodity prices and service costs.

Rationalization of Properties

We may from time to time, dispose of properties at prices that are accretive to shareholder value so that we can focus on the development of Montney liquids rich natural gas on our Birley/Umbach BC properties and our Montney and Dunvegan light crude oil in Grande Prairie, Alberta. As a result, during the first quarter we completed the sale of petroleum and natural gas properties including undeveloped lands located in the Karr area of northwestern Alberta for net proceeds of $41.1 million. These properties were classified as held for sale in the December 31, 2014 reported balances of the Interim Financial Statements and Annual Financial Statements. Our production from these properties immediately prior to their sale was approximately 485 boe/d. Also during the first quarter, we completed the sale of undeveloped lands in the Knopcik area and reported purchase price adjustments totalling $0.6 million. The combined first quarter proceeds on property dispositions and price adjustments of $41.7 million was used to fund our capital expenditures program of $22.1 million with the remainder added to working capital resulting in a net surplus of $48.6 million.

Accrued Transaction and Indemnification Costs on Discontinued Operations

SVI (BVI) provided the purchaser of the Discontinued Operations with indemnities pursuant to a share purchase and sale agreement dated as of June 14, 2014 (the “PSA”) which indemnities Chinook Energy Inc. has guaranteed in accordance with the PSA. As of March 31, 2015, an estimate for these indemnifications in addition to unpaid transaction costs totaled $2.6 million. During the first quarter we paid $0.2 million of such costs as reported on the condensed consolidated statements of cash flow as a change in investing activities from discontinued operations.

Provisions

Our provision balance mostly relates to the future abandonment and reclamation of our properties. At March 31, 2015, we had provisions of $107.2 million which was an increase from $106.7 million at December 31, 2014. This estimated increase resulted from additions of $0.3 million related to our first quarter drilling program and $0.6 million of accretion charges (same quarter of 2014 - $0.2 million and $0.7 million, respectively). The recognized accretion charges reflect the increase in the decommissioning obligation associated with the passage of time. Partially offsetting these increases were decommissioning obligation expenditures of $0.5 million (same quarter of 2014 - $0.6 million).

As at March 31, 2015 and December 31, 2014, the estimated decommissioning obligation included assumptions of the actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred and an annual inflation of 2.0% in order to calculate the future obligation. At March 31, 2015 and December 31, 2014, a risk-free interest rate of 2.3% was used to calculate the present value of the decommissioning obligation.

Outstanding Share Data

Authorized:

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

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

	March 31 2015	December 31 2014
Common shares outstanding	**215,083,496**	215,082,199
Share options	**9,385,005**	10,529,675
Restricted awards	**196,225**	206,590
Performance awards	**237,790**	244,375

As at May 8, 2015, we had 215,083,827 common shares, 9,110,753 share options, 247,335 restricted awards and 234,380 performance awards outstanding.

Outlook

We are currently well positioned with a strong balance sheet providing us the flexibility and optionality to evaluate potential corporate or asset-based acquisitions. Balance sheet strength is an important determinant of share price performance, more so during periods such as now, and maintaining financial strength is a clear component of our 2015 strategy. We anticipate that if weak commodity prices continue to persist that the opportunities to acquire quality assets at attractive economics will increase throughout the remainder of the year. We will evaluate these opportunities as they present themselves and will look to complete acquisitions that serve to complement our core assets and reduce our overall cost structure by exploiting synergies with our current operations and improving our operational efficiencies. There are generally more reasons to see improvements in our business than weakness from this point forward.

We maintain our guidance for 2015 as previously released on March 9, 2015 and will continue to review cost savings and optimization initiatives which may include the further shut-in of lower netback production if pricing and economics do not improve.

Quarterly Information from Continuing Operations

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

	Mar. 31 2015	Dec. 31 2014	Sep. 30 2014	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	Jun. 30 2013
CONTINUING CANADIAN OPERATIONS								
Production Volumes								
Crude oil (bbl/d)	**1,485**	1,981	1,823	2,267	2,084	1,840	1,853	1,606
Natural gas liquids (boe/d)	**682**	778	678	715	950	722	753	874
Natural gas (mcf/d)	**33,007**	34,879	29,028	29,570	29,364	32,287	34,563	33,226
Average daily production (boe/d)	**7,668**	8,572	7,339	7,911	7,928	7,943	8,367	8,018
Sales Prices								
Average oil price ($/bbl)	**$ 49.03**	$ 70.84	$ 93.10	$ 101.01	$ 96.41	$ 81.18	$ 97.53	$ 92.43
Average natural gas liquids price ($/boe)	**$ 36.47**	$ 48.05	$ 64.71	$ 72.06	$ 74.10	$ 63.74	$ 62.36	$ 55.06
Average natural gas price ($/mcf)	**$ 2.65**	$ 3.57	$ 4.11	$ 4.89	$ 6.01	$ 3.57	$ 2.55	$ 3.74
Netback (1)								
Average commodity pricing ($/boe)	**$ 24.15**	$ 35.26	$ 45.37	$ 53.75	$ 56.50	$ 39.09	$ 37.76	$ 40.02
Royalties ($/boe)	**$ (2.07)**	$ (4.74)	$ (6.90)	$ (8.47)	$ (6.01)	$ (4.80)	$ (3.53)	$ (5.23)
Net production expenses ($/boe) (1)	**$ (17.04)**	$ (18.89)	$ (17.44)	$ (17.06)	$ (16.91)	$ (15.83)	$ (16.42)	$ (15.55)
G&A expense ($/boe)	**$ (4.00)**	$ (4.26)	$ (4.32)	$ (4.30)	$ (6.46)	$ (3.47)	$ (1.71)	$ (2.76)
Netback ($/boe) (1)	**$ 1.04**	$ 7.37	$ 16.71	$ 23.92	$ 27.12	$ 14.99	$ 16.10	$ 16.48
Wells Drilled (net)								
Oil	**-**	1.62	1.26	-	3.26	1.65	3.00	-
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	1.65	3.00	-
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties	**$ 15,240**	$ 24,065	$ 25,972	$ 32,596	$ 36,029	$ 25,055	$ 26,347	$ 25,385
Funds from operations (1)	**$ 1,220**	$ 6,069	$ 9,693	$ 14,801	$ 17,596	$ 8,786	$ 12,213	$ 10,662
Per share - basic and diluted ($/share)	**$ 0.01**	$ 0.03	$ 0.05	$ 0.07	$ 0.08	$ 0.04	$ 0.06	$ 0.05
Net income (loss) from continuing operations (2)	**$ 8,189**	$ (58,311)	$ 3,696	$ 3,533	$ 410	$ (10,151)	$ (316)	$ 3,682
Per share - basic and diluted ($/share)	**$ 0.04**	$ (0.27)	$ 0.02	$ 0.02	$ -	$ (0.05)	$ -	$ 0.02
Net income (loss) (2)(3)(4)	**$ 8,189**	$ (60,348)	$ 11,472	$ 4,391	$ 6,085	$ (39,002)	$ 3,812	$ 3,989
Per share - basic and diluted ($/share)	**$ 0.04**	$ (0.28)	$ 0.05	$ 0.02	$ 0.03	$ (0.18)	$ 0.02	$ 0.02
Capital expenditures and business combination	**$ 22,093**	$ 39,671	$ 14,301	$ 18,998	$ 23,614	$ 9,854	$ 10,014	$ 5,506
Net debt (surplus) (1) (5)	**$ (48,596)**	$ (28,788)	$ (35,870)	$ 80,536	$ 74,390	$ 61,849	$ 65,105	$ 66,340
Total assets (5)	**$ 431,085**	$ 434,318	$ 472,241	$ 589,515	$ 604,419	$ 555,341	$ 593,192	$ 621,143
Common Shares (thousands)								
Weighted average during period - basic	**215,083**	215,081	214,895	214,226	214,188	214,188	214,188	214,188
Weighted average during period - diluted	**215,112**	215,081	216,773	215,814	214,245	214,188	214,188	214,188
Outstanding at period end	**215,083**	215,082	215,079	214,674	214,188	214,188	214,188	214,188

(1) Funds from operations, funds from operations per share, net debt (surplus), netback and net production expense are non-IFRS measures as defined and calculated throughout this MD&A. These terms 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.

(2) Includes $3.5 million and $63.5 million in impairment charges against properties for the three months ended December 31, 2013 and 2014, respectively.

(3) Quarters prior to and including December 31, 2014 include net income or loss from Discontinued Operations, including a reported $32.0 million in impairment charges against the Discontinued Operations for the three months ended December 31, 2013.

(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.

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 production volumes decreased reflecting the impact of significant dispositions in our Gilby and Karr areas during the fourth quarter of 2014 and the first quarter, respectively, in addition to voluntary shut-ins of properties with high operating costs/low netbacks. 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 the first quarter. Changes in benchmark commodity prices has generally trended with our petroleum and natural gas revenues, net of royalties and funds from operations. 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 dispositions have since increased our net surplus. Our dispositions of non-core assets and our management of organic growth and business acquisitions relative to our existing funds from operations 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, 2014 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 the risks, assumptions and uncertainties are found under the heading "Forward-Looking Statements".

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting 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 January 1, 2015 and ended on March 31, 2015, that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

We have designed our internal controls over financial reporting based on the framework in *Internal Control over Financial Reporting – Guidance for Smaller Public Companies* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013.

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

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: how we intend to manage the current capacity throughput at our Birley/Umbach compression facility, the anticipated timing of bringing our second Montney horizontal well on production, the expected impact of utilizing a water disposal well at Gold Creek on operating costs and the economics of follow-up wells, our forecasted production and operating costs for the year ended 2015, our forecasted G&A costs for the year ended 2015, the timing of the redetermination of our credit facility's revolving period and availability, expectations regarding future reductions in operating and G&A costs, budgeted amounts in fiscal 2015, expectations that such amounts will be spent in the manner, location and timeframes set forth herein, expectations as to how we will fund the 2015 capital program, future exploration and development activities and the timing thereof, as well as our expectations regarding production, general and administrative expenses, production and operating expenses, funds from operations, net debt (surplus) and capital expenditures set out in our guidance for 2015 as previously released on March 9, 2015.

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 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 2015 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. Boes 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.

Initial Production Levels

Any references in this MD&A to initial, early and/or test production/performance rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating our aggregate production. The initial production rate may be estimated based on other third party estimates or limited data available at this time. The initial production is generally estimated using boes. In all cases in this MD&A initial production or test rates are not necessarily indicative of long-term performance of the relevant well or fields or of ultimate recovery of hydrocarbons.

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.