Q2
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 and six months ended June 30, 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 and six months ended June 30, 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 August 11, 2015.

The term "second quarter" and "year to date" or similar terms are used throughout this document and refer to the three and six months ended June 30, 2015, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three and six months ended June 30, 2015, in this respective order. The term "same period(s) of 2014" or similar terms are used throughout this document and refer to either the three or (and) six months ended June 30, 2014, 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 "Additional GAAP Measures", Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 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 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.

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 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 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.

Financial and Operating Highlights

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
CONTINUING CANADIAN OPERATIONS (1) (2)				
Production				
Crude oil (bbl/d)	**1,284**	2,267	**1,384**	2,176
Natural gas liquids (boe/d)	**604**	715	**643**	832
Natural gas (mcf/d)	**25,290**	29,570	**29,128**	29,468
Average daily production (boe/d)	**6,103**	7,911	**6,881**	7,919
Sales Prices				
Average oil price ($/bbl)	**$ 62.90**	$ 101.01	**$ 55.50**	$ 98.82
Average natural gas liquids price ($/boe)	**$ 41.06**	$ 72.06	**$ 38.64**	$ 73.22
Average natural gas price ($/mcf)	**$ 2.50**	$ 4.89	**$ 2.59**	$ 5.45
Netback (3)				
Average commodity pricing ($/boe)	**$ 27.67**	$ 53.75	**$ 25.72**	$ 55.12
Royalties ($/boe)	**$ (0.78)**	$ (8.47)	**$ (1.49)**	$ (7.25)
Net production expenses ($/boe) (3)	**$ (18.36)**	$ (17.06)	**$ (17.63)**	$ (16.99)
G&A expense ($/boe)	**$ (3.70)**	$ (4.30)	**$ (3.87)**	$ (5.37)
Netback ($/boe) (3)	**$ 4.83**	$ 23.92	**$ 2.73**	$ 25.51
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	**$ 14,934**	$ 32,595	**$ 30,174**	$ 68,624
Funds from operations (4)	**$ 2,995**	$ 14,798	**$ 4,218**	$ 32,394
Per share - basic and diluted ($/share)	**$ 0.01**	$ 0.07	**$ 0.02**	$ 0.15
Net (loss) income from continuing operations	**$ (5,822)**	$ 3,531	**$ 2,366**	$ 3,941
Per share - basic and diluted ($/share)	**$ (0.03)**	$ 0.02	**$ 0.01**	$ 0.02
Net (loss) income (5)	**$ (5,822)**	$ 4,391	**$ 2,366**	$ 10,476
Per share - basic and diluted ($/share)	**$ (0.03)**	$ 0.02	**$ 0.01**	$ 0.05
Capital expenditures	**$ 4,921**	$ 18,998	**$ 27,014**	$ 42,611
Net debt (surplus) (3) (6)	**$ (46,705)**	$ 80,536	**$ (46,705)**	$ 80,536
Total assets (5)	**$ 414,280**	$ 589,515	**$ 414,280**	$ 589,515
Common Shares (thousands)				
Weighted average during period				
- basic	**215,089**	214,226	**215,087**	214,207
- diluted	**215,089**	215,814	**215,121**	214,916
Outstanding at period end	**215,236**	214,674	**215,236**	214,674

(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.

(4) Refer to the sections "Funds from Operations" and "Additional GAAP Measures" contained within this MD&A.

(5) The comparative periods include the Discontinued Operations' net income or assets, as applicable.

(6) The comparative periods include the Discontinued Operations' working capital excluding marked-to-market derivative contracts.

Continuing Canadian Operations

Petroleum and Natural Gas Production Volumes

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
Crude oil (bbl/d)	**1,284**	2,267	**1,384**	2,176
Natural gas liquids (boe/d)	**604**	715	**643**	832
Natural gas (mcf/d)	**25,290**	29,570	**29,128**	29,468
Total (boe/d)	**6,103**	7,911	**6,881**	7,919

Total Production Volumes

Our production volumes for the current reporting periods decreased 1,808 boe/d and 1,038 boe/d, or 23% and 13%, compared to the same periods of 2014. These decreases resulted from both the year to date and 2014 dispositions of producing properties that had associated production of approximately 1,450 boe/d at the time of their sale. In addition, scheduled third party plant restrictions and turnarounds during the second quarter reduced our current reporting periods' production by approximately 1,125 boe/d and 575 boe/d. Finally, to date we have shut-in approximately 600 boe/d of production in response to lower commodity prices. Partially offsetting these decreases was 825 boe/d and 1,200 boe/d of production, during the current reporting periods, 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% owned and operated acquisition included key infrastructure which we believe strategic to the long term delivery of volumes from this area.

As scheduled in our 2015 capital program, we did not drill or complete any new wells during the second quarter due to spring break up conditions in the field. We have revised the remainder of our 2015 planned capital program. This revised capital program now includes the expansion of the Birley/Umbach compression facility and the completion of another three (2.75 net) previously drilled wells in this area, all of which had originally been budgeted for the first quarter of 2016. The expansion of this compression facility from nine mmcf/d to 35 mmcf/d will allow us to bring the production on-stream from these three wells (2.75 net) and an additional well (0.75 net) that is currently standing.

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 approximately 800 boe/d and a scheduled third party plant turnaround during the second quarter which affected production from our Montney play in British Columbia. As mentioned, we have also voluntarily shut-in approximately 600 boe/d of production, which includes natural gas production. Partially offsetting these decreases were 6,600 mcf/d and 10,700 mcf/d of natural gas production associated with both last year's property acquisitions and our successful drilling program in the Birley/Umbach area. 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 111 boe/d and 189 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 983 bbl/d and 792 bbl/d compared to the same periods of 2014. These decreases 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 approximately 485 boe/d at their time of sale. Also causing these decreases was crude oil production associated with 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 June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2015**	2014	**2015**	2014
Oil sales	**$ 7,348**	$ 20,840	**$ 13,901**	$ 38,927
$/bbl	**62.90**	101.01	**55.50**	98.82
Natural gas liquids sales	**$ 2,257**	$ 4,690	**$ 4,495**	$ 11,023
$/boe	**41.06**	72.06	**38.64**	73.22
Natural gas sales	**$ 5,762**	$ 13,166	**$ 13,639**	$ 29,060
$/mcf	**2.50**	4.89	**2.59**	5.45
Petroleum and natural gas revenue	**$ 15,367**	$ 38,696	**$ 32,035**	$ 79,010
$/boe	**27.67**	53.75	**25.72**	55.12

Our petroleum and natural gas revenues of $15.4 million and $32.0 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 a decrease in sales volumes. The decreases 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 21% and 20% during the current reporting periods compared to 29% and 27% in the same periods of 2014, further contributing to lower realized weighted average commodity prices. These decreased ratios were the result of the disposition of our oil weighted Karr properties in combination with the 2014 acquisition of natural gas weighted properties.

Benchmark Prices

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
Crude oil				
Canadian light sweet (1) ($/bbl)	**$ 68.88**	$ 106.67	**$ 61.08**	$ 103.42
Natural gas liquids				
WTI (2) ($US/bbl)	**$ 57.94**	$ 102.99	**$ 53.29**	$ 100.84
Natural gas				
AECO gas (3) ($/mcf)	**$ 2.69**	$ 4.76	**$ 2.74**	$ 5.28

(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. The declines in our average realized crude oil prices was less than the decline in the WTI benchmark, during the current reporting periods compared to the same periods of 2014, as the weakening of this US dollar denominated benchmark price was partially offset by a weakening Canadian dollar.

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 $41.06/boe and $38.64/boe decreased compared to $72.06/boe and $73.22/boe for the same periods of 2014. The ratio of our NGL price relative to Canadian light sweet oil was 60% and 63% for the current reporting periods compared to 68% and 71% for comparative periods of 2014. The decreases in this ratio was due to a lower average price for propane which fell by 95% and 89% during the current reporting periods compared to the same periods of 2014.

Natural Gas Pricing

Our realized natural gas price of $2.50/mcf and $2.59/mcf for the current reporting periods decreased from $4.89/mcf and $5.45/mcf for the same periods of 2014. These decreases were due to both lower AECO and other Alberta and BC natural gas trading hub pricing benchmarks. 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 current reporting periods, a portion of this natural gas production was sold at other Alberta and BC trading hub spot prices which experienced pricing volatility. The spot pricing volatility is a consequence of third party pipeline restrictions resulting from an ongoing service outage which forced us and other producers who had firm delivery volumes to divert their production to another third party pipeline, or curtail delivery. Various pipeline restrictions caused, and continue to cause, volume increases and downward price pressures at the various sales points.

Royalties

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Royalties	**$ 433**	$ 6,101	**$ 1,861**	$ 10,386
Per sales ($/boe)	**$ 0.78**	$ 8.47	**$ 1.49**	$ 7.25
Percent of revenues (%)	**3**	16	**6**	13

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 partially resulted from adjustments to our gas cost allowance during the second quarter. In addition, the decreases in our royalties on an overall and on a boe basis also resulted from lower realized prices in the current reporting periods compared to the same periods of 2014. As consequence of the volatile BC trading hub 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 current reporting periods compared to the same periods of 2014.

During the second quarter, the newly elected Alberta provincial government announced that it will be completing a review of the current royalty regime. The change to royalty rates, if any, and the timeline for implementing these changes has not yet been determined; however, a modification to the current royalty regime may have an impact on the economics of our Alberta projects. During the current reporting periods, 67% and 65% of our production came from our Alberta properties. Going forward, as we continue to focus on the development of our Montney play in the Birley/Umbach area of BC, we expect the proportion of our production from BC to increase.

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 contracts as compared to our received price multiplied by the remaining notional volumes. Volatility in the commodity price and any decrease in the remaining notional volumes will result in changes in the fair value of our derivative contracts from one period to the next. The change in the fair values between reporting periods are recognized in net income (loss) as unrealized gains or losses on derivative contracts. Realized gains or losses on the derivative contracts are recognized in net income (loss) on the unwinding of the financial derivative contract term.

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 June 30		Six months ended June 30	
($ thousands)	**2015**	2014	**2015**	2014
Realized (gains) losses on derivative contracts	**$ (441)**	$ 1,697	**$ (741)**	$ 2,871
Unrealized losses (gains) on derivative contracts	**398**	(1,686)	**684**	2,075
Total	**$ (43)**	$ 11	**$ (57)**	$ 4,946

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 $2.70/mcf and $2.73/mcf compared to our reported prices of $2.50/mcf and $2.59/mcf.

Our unrealized losses for the current reporting periods resulted from the unwinding of the AECO derivative contract over its term as its unrealized fair value became realized. As at June 30, 2015, this commodity price contract had an estimated current asset fair value of $0.8 million with the following terms:

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

Based on our 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 June 30		Six months ended June 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Production & operating	**$ 11,026**	$ 13,750	**$ 23,856**	$ 27,131
Less:				
Processing & gathering revenues	**(786)**	(1,466)	**(1,856)**	(2,784)
Net production & operating expense [(1)]	**$ 10,240**	$ 12,284	**$ 22,000**	$ 24,347
Per sales net production & operating expenses ($/boe) [(1)]	**$ 18.36**	$ 17.06	**$ 17.63**	$ 16.99
Per sales production & operating expenses ($/boe)	**$ 19.85**	$ 19.10	**$ 19.15**	$ 18.93

(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 $11.0 million and $ 23.9 million decreased compared to the same periods 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. On a per boe basis, efficiencies in our cost structure related to our ongoing effort to better manage our costs are not being reflected as a result of the aforementioned production declines due to third party plant restrictions and turnarounds and the impact of the carrying costs of shut-in wells. We continued to incur carrying costs on these properties despite their reduced production.

To date we have voluntarily shut-in approximately 600 boe/d of production from lower netback wells. Early in the second quarter, in response to decreased commodity prices, we voluntarily shut-in additional higher operating cost/lower netback wells. These wells are mostly located on our Hoffard, Pouce Coupe, Marten Hills, Rainbow, Enchant and Rigel properties. Had these properties been shut-in at the beginning of the year, and ignoring the effect of one-time shut-in costs and carrying costs, our reported production & operating costs in total and on a boe basis for the year to date would have been approximately $22.6 million and $18.16/boe, respectively, with only a 225 boe/d decrease in our reported production volumes.

Partially offsetting the decreases in production and operating costs during the current reporting periods relative to the comparative periods, were higher production costs associated with our recent development of Montney projects at Gold Creek and Birley/Umbach and properties acquisition in Birley/Umbach. 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 development project located at Gold Creek, the current reporting periods' production and operating costs on a boe basis were also affected by continued third party pipeline and plant capacity constraints in the Grande Prairie area. We shut-in this production 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 and as a result, beginning in April, we recommenced production from this project and began to dispose of the associated water down a well that was drilled in the third quarter of 2014. Since we began using this water disposal well we have realized a $10/boe reduction in our operating costs at this project.

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 current reporting periods' operating costs in total and on a boe basis compared to the same quarter of 2014. For the year to date, we also incurred one-time increased field staff costs as we replaced certain positions in addition to cathodic protection and calibration services. As mentioned, our revised 2015 capital program includes expansion of the compression facility and the completion of another three wells (2.75 net) previously drilled in this area. We expect decreases in both our operating costs overall and on a boe basis during 2016 as implemented cost saving initiatives take effect and sales volumes from the three completed wells and an additional standing well 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 current reporting periods compared to the same periods of 2014. The sale of the Gilby area properties during the fourth quarter of 2014 included certain processing facilities and distribution pipelines.

General & Administrative ("G&A") Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
G&A expense	**$ 2,053**	$ 3,087	**$ 4,814**	$ 7,708
Per sales ($/boe)	**$ 3.70**	$ 4.30	**$ 3.87**	$ 5.37

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 and a boe basis, during the current reporting periods compared to the same periods of 2014. For the year to date, these decreases were achieved despite incurring $0.4 million in severance costs from staffing reductions. Removing the effect of the non-reoccurring severance costs resulted in a year to date G&A expense of $4.4 million or $3.55/boe.

On a boe basis, we achieved decreases during the current reporting periods despite lower production volumes compared to the same periods of 2014. Our second quarter G&A expense per boe continued to decrease compared to the $4.00/boe and $4.26/boe we realized during the first quarter of 2015 and fourth quarter of 2014, respectively. These decreases reflect our continued effort to reduce G&A expense.

As part of our ongoing evaluation of our G&A cost structure, we consequently reduced our staffing and consultant levels in 2015 in addition to implementing other cost saving initiatives. Beginning mid-way through the second quarter, we implemented 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. As the full effect of these reductions are realized we expect to continue to report materially lower G&A costs in the remaining quarters of 2015. During the current reporting periods, our G&A also decreased due to an incremental $0.1 million and $0.3 million related party recovery. During 2015, we expect this related party recovery increase to be maintained. We will continue to evaluate our existing G&A cost structure and implement cost savings initiatives throughout 2015. We anticipate meeting our updated forecasted G&A costs for the year ended 2015 of between $9.6 million and $10.1 million.

Netback

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

	Three months ended June 30		Six months ended June 30	
Per sales ($/boe)	**2015**	2014	**2015**	2014
Realized sales price	**$ 27.67**	$ 53.75	**$ 25.72**	$ 55.12
Less:				
Royalties	**(0.78)**	(8.47)	**(1.49)**	(7.25)
Net production expense (1)	**(18.36)**	(17.06)	**(17.63)**	(16.99)
G&A expense	**(3.70)**	(4.30)	**(3.87)**	(5.37)
Netback (1)	**$ 4.83**	$ 23.92	**$ 2.73**	$ 25.51

(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. Also contributing to these decreases was a lower proportion of crude oil sales volumes relative to total sales volumes. Despite our realized crude oil prices during the current reporting periods being essentially one-half of what they were for the comparative periods of 2014, 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 decreases were partially offset by lower royalties and G&A on a boe basis. We are reporting lower royalties on a boe basis due to the effect of lower commodity pricing and favourable adjustments to our gas cost allowance. The decreases in G&A on a boe basis resulted from staffing and consulting headcount reductions, the implementation of a temporarily reduced work week, an increase in recoveries from a related party and other cost saving initiatives. We will continue to strive to implement cost saving initiatives throughout 2015 to reduce these costs.

Exploration and Evaluation Expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2015**	2014	**2015**	2014
Exploration and evaluation expenditures	**$ 424**	$ 116	**$ 917**	$ 585

Exploration and evaluation expense during the current and comparative periods was due to pre-licensing evaluation, exploratory lease rental, and geological and geophysical costs. These costs increased during the current reporting periods primarily as a result of the lease costs associated with the 2014 acquisitions of undeveloped properties in our Birley/Umbach area.

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

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Depletion, depreciation and amortization	**$ 8,982**	$ 12,346	**$ 19,490**	$ 24,633
Per sales ($/boe)	**$ 16.17**	$ 17.15	**$ 15.65**	$ 17.18

DD&A expense decreased during the current reporting periods as a result of the lower depletion rates and production volumes when compared to the same periods of 2014. The decrease in our overall depletion rates was 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 on our Birley/Umbach properties. In addition, our overall depletion rates decreased as a result of the disposition of the Karr producing properties with their higher associated rate. The decreases in the rates 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 current reporting periods. For our D&P Assets as at June 30, 2015, we assessed whether there were any triggers indicating impairment of these assets. During the first half or 2015, 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. As an offset to weakening commodity prices, we are starting to observe pricing concessions from third party vendors which should decrease our future development and operating costs. 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 year to date have not provided any additional information which would challenge our previous assumptions included in our December 31, 2014 measure of value-in-use. 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 June 30, 2015, there was no overall trigger indicating impairment of our D&P Assets.

Gains on Disposition of Properties

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2015**	2014	**2015**	2014
Gains on disposition of properties	**$ (2,390)**	$ (166)	**$ (21,793)**	$ (166)

During the year to date we completed the sale of several properties for aggregate proceeds of $42.9 million. These dispositions included the sale of certain petroleum and natural gas properties including undeveloped lands located in the Karr area of northwestern Alberta, which 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.

During the current reporting periods, we participated in three swap transactions. We assessed the fair value of the properties and lands received in the swap transactions based on the fair value of the properties and lands we gave up. We used recent market sales transactions of similar properties and lands to determine their fair value. The carrying amount of these swapped properties was $0.6 million.

The total reported gains from property dispositions for the current reporting periods were $2.4 million and $21.8 million compared to $0.2 million for the same periods of 2014.

Share-Based Compensation

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2015**	2014	**2015**	2014
Share-based compensation	**$ 623**	$ 109	**$ 1,049**	$ 303

For the current reporting periods, share-based compensation increased as a result of amortizing the fair value related to the restricted and performance awards. These awards were granted for the first time late in the second quarter of 2014. The first tranche of this first grant was fully amortized by the second quarter at which time they vested. During the second quarter, an additional two million of these awards were granted. Finally, the increases in share-based compensation include amortizing the fair value of share options granted subsequent to the second quarter of 2014.

Bad Debt Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Bad debt expense	**$ 57**	$ 46	**$ 554**	$ 66

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 year to date reporting, we identified joint venture partners that filed for creditor protection. As a result, for the year to date we provided for $0.6 million of joint venture partner receivables that were deemed uncollectible.

Foreign Exchange & Other Losses (Gains)

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2015**	2014	**2015**	2014
Foreign exchange and other losses (gains)	**$ 172**	$ (139)	**$ (290)**	$ (301)

During the second quarter we recognized a foreign exchange loss whereas for the year to date we recognized a gain from holding US$4.7 million as a natural hedge to the estimated $2.8 million of US dollar denominated indemnifications we provided to the buyer of the Discontinued Operations.

Financing Expenses

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2015**	2014	**2015**	2014
Interest and financing charges (income)	**$ 16**	$ 881	**$ (115)**	$ 1,591
Amortization of deferred financing costs	**-**	75	**-**	149
Accretion of decommissioning obligation	**622**	678	**1,239**	1,350
Total	**$ 638**	$ 1,634	**$ 1,124**	$ 3,090

Interest and financing charges were essentially nil for the current reporting periods as interest income offset the standby fees on our available credit facility. The interest income from our cash deposits, which were $50.7 million at June 30, 2015, is competitive to other short-term liquid investments. For the majority of the current reporting periods, the standby fees were based on a credit facility availability of $125.0 million. As discussed under the section "Credit Facility" of this MD&A, the facility agreement was amended resulting in a revised availability of $75.0 million. Given we are not forecasting to draw on this facility during 2015, and as a result of the decrease in the availability of this credit facility, we anticipate lower standby fees during the remainder of 2015.

During the comparative periods of 2014, we incurred interest expense on our outstanding credit facility balance, which increased from $78.5 million to $97.8 million mid-way through the second quarter of 2014, 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 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 discount rate when accounting for the passage of time related to the decommissioning obligation.

Income Tax Expense

The newly elected Alberta provincial government raised the provincial corporate tax rate, as substantively enacted on June 29, 2015, from 10% to 12%. 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.

Net and Comprehensive (Loss) Income

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Weighted average shares outstanding - basic (thousands)	**215,089**	214,226	**215,087**	214,207
Dilutive impact of share options (thousands)	**-**	1,588	**34**	709
Weighted average shares outstanding - diluted (thousands)	**215,089**	215,814	**215,121**	214,916
Net (loss) income from continuing operations	**$ (5,822)**	$ 3,531	**$ 2,366**	$ 3,941
Per share - basic & diluted ($/share)	**$ (0.03)**	$ 0.02	**$ 0.01**	$ 0.02
Net income from discontinued operations	**$ -**	$ 860	**$ -**	$ 6,535
Per share - basic & diluted ($/share)	**$ -**	$ -	**$ -**	$ 0.03
Net (loss) income	**$ (5,822)**	$ 4,391	**$ 2,366**	$ 10,476
Per share - basic & diluted ($/share)	**$ (0.03)**	$ 0.02	**$ 0.01**	$ 0.05
Comprehensive (loss) income	**$ (5,822)**	$ (169)	**$ 2,366**	$ 10,658
Per share - basic and diluted ($/share)	**$ (0.03)**	$ (0.00)	**$ 0.01**	$ 0.05

During the second quarter we reported net loss from continuing operations compared to net income during the same quarter of 2014. For the year to date, our net income from continuing operations decreased compared to the same period of 2014. These decreases resulted from lower petroleum and natural gas revenues due to the effect of both lower sales volumes and a decrease in our realized commodity prices. Partially offsetting these decreases were gains on property dispositions of $2.4 million and $21.8 million in addition to lower charges for operating, G&A, depletion and financing costs.

Our net income for the comparative periods also included the financial results from the Discontinued Operations. In addition to including net income, our comprehensive loss for the second quarter of 2014 and comprehensive income for the year to date of 2014 also included a foreign exchange loss and gain, respectively, 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

We have revised our 2015 capital program from $45.0 million to $55.0 million to accelerate a facility expansion and a completions program targeting our Montney resource at Birley/Umbach, BC, while deferring our originally planned drilling and completions work at Gold Creek, Alberta. We expect that accelerating the timing of our capital activity at Birley/Umbach, from early 2016 to the second half of 2015, will allow us to accelerate the realization of current cost efficiencies while taking advantage of a period of lower operational and industry activity and more favourable weather conditions. Expanding our Birley/Umbach facility will allow us to be well positioned for the expected increase in production volumes from our 2016 drilling program. We plan to fund this increased 2015 capital program through our existing net surplus position which included $50.7 million of cash on hand at June 30, 2015.

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

Funds from Operations

	Three months ended June 30		Six months ended June 30	
($ thousands, except per share amounts)	**2015**	2014	**2015**	2014
Funds from operations [1]	**$ 2,995**	$ 14,798	**$ 4,218**	$ 32,394
Per share - basic and diluted	**$ 0.01**	$ 0.07	**$ 0.02**	$ 0.15
Per sales ($/boe)	**$ 5.39**	$ 20.56	**$ 3.39**	$ 22.60

(1) Funds from operations is an additional GAAP measure, which does not have a standardized meaning as prescribed by IFRS. Refer to the section entitled "Additional GAAP Measures" contained within this MD&A.

During the current reporting periods, our funds from operations significantly decreased to $3.0 million and $4.2 million compared to $14.8 million and $32.4 million in the same periods of 2014. These decreases were due to considerably lower netbacks and a decrease in sales volumes. The decreases in the netbacks resulted from significantly lower benchmark prices and a decrease in the proportion of our crude oil production. The decreases in the sales volumes resulted from the scheduled plant restrictions and turnarounds during the second quarter, the Karr and Gilby property dispositions, voluntary shut-ins and capacity constraints at our Montney liquids rich development. Partially offsetting these decreases were realized gains from our derivative contract and lower costs. The most notable cost decreases were for G&A and cash financing charges. G&A costs decreased $1.0 million and $2.9 million during the current reporting periods due to headcount reductions of both personnel and consultants, implemented cost saving initiatives, including a reduced work week and a higher related party recovery. For the current reporting periods, income from cash on deposit approximated the standby fees on our credit facility resulting in an increase in funds from operations of $0.9 million and $1.7 million compared to the same periods of 2014 when we had outstanding debt with associated interest charges. We also had realized gains in the current reporting periods from our derivative contract which increased funds from operations by $2.1 million and $3.6 million compared to losses on similar contracts for the same periods of 2014. As a result of both 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 current reporting periods.

Credit Facility

($ thousands)	June 30 2015	December 31 2014
Long-term debt	**$ -**	$ -
Less:		
Working capital excluding mark-to-market derivative contracts and assets and liabilities held for sale (1)	**(46,705)**	(28,788)
Net debt (surplus) (1)	**$ (46,705)**	$ (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 June 30, 2015. We had a net surplus of $46.7 million at June 30, 2015, compared to $28.8 million at December 31, 2014. This positive change of $17.9 million was due to the proceeds of $42.9 million received mostly from the Karr property disposition and $4.2 million from funds from operations which excluded $0.4 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 $29.6 million.

On June 22, 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 $75.0 million, down from $125.0 million at December 31, 2014, primarily as a result of significantly reduced commodity pricing and 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 June 30, 2015 and December 31, 2014, we were undrawn on our Revolving Term Credit Facility, but had an outstanding letter of credit of $0.3 million, as secured by our lending syndicate, which reduced the available credit to $74.7 million and $124.7 million, respectively.

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 June 30		Six months ended June 30	
($ thousands)	**2015**	2014	**2015**	2014
Land and lease	**$ 17**	$ 14,041	**$ 129**	$ 14,202
Drilling and completions	**993**	1,279	**12,664**	19,722
Facilities and equipment	**3,599**	3,410	**13,604**	7,866
Field expenditures	**4,609**	18,730	**26,397**	41,790
Capitalized G&A	**258**	268	**557**	541
Furniture and equipment	**54**	-	**60**	280
Total	**$ 4,921**	$ 18,998	**$ 27,014**	$ 42,611
Proceeds from dispositions	**$ 1,200**	$ 33	**$ 42,935**	$ 33

During the second quarter, due to spring breakup, we did not conduct any new field operations. Our capital expenditures for the second quarter related to our Birley/Umbach development. These expenditures included equipping a well (0.75 net), connecting another well (1.0 net) and upfront equipment costs associated with the capacity expansion at our Birley/Umbach compressor station. We also conducted an evaluation of our strategic 12 inch sales pipeline in that area to determine if it could be converted to carry raw sour natural gas allowing us to deliver our Montney production to our Martin Creek facility in addition to considering other options. If feasible, we could avoid existing third party plant restrictions in this area.

We have revised our planned capital program for the remainder of 2015 and now expect to complete the first phase expansion of the compression facility in our Birley/Umbach area during the fourth quarter of 2015. This expansion had previously been planned for the first quarter of 2016. This expansion will increase our facility's capacity from nine mmcf/d to 35 mmcf/d. The additional throughput capacity resulting from this facility expansion will enable us to bring a previously completed well back on-stream as well as accelerate the completion of three wells previously drilled during the fourth quarter of 2014.

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 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 area of northwestern Alberta, in addition to other minor dispositions and customary closing adjustments, for net proceeds of $42.9 million. The Karr 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. The combined year to date proceeds on property dispositions and price adjustments of $42.9 million in addition to funds from operations were used to fund our capital expenditures program of $27.0 million with the remainder added to working capital resulting in a net surplus increase from $28.8 million at December 31, 2014 to $46.7 million at June 30, 2015.

Non-Monetary Property Swaps

During the current reporting periods, we participated in three swap transactions. We determined that the fair value of the properties and lands that we swapped for undeveloped lands was $1.8 million. The carrying amount of these swapped properties was $0.6 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 June 30, 2015, an estimate for these indemnifications in addition to unpaid transaction costs totaled $2.6 million. During the current reporting periods we paid $0.1 million and $0.4 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 primarily relates to the future abandonment and reclamation of our properties. At June 30, 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 $1.2 million of accretion charges (same period of 2014 - $1.4 million). The recognized accretion charges reflect the increase in the decommissioning obligation associated with the passage of time. Partially offsetting this increase was decommissioning obligation and other expenditures of $1.0 million (same period of 2014 - $1.2 million).

As at June 30, 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 June 30, 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:

	June 30 2015	December 31 2014
Common shares outstanding	**215,235,807**	215,082,199
Share options	**9,200,570**	10,529,675
Restricted awards	**1,163,506**	206,590
Performance awards	**1,118,844**	244,375

As at August 10, 2015, we had 215,249,662 common shares, 8,575,281 share options, 1,158,236 restricted awards and 1,113,121 performance awards outstanding.

Outlook

We are currently well positioned with a strong balance sheet providing us the flexibility and optionality to accelerate the development of our Montney resource at Birley/Umbach and Gold Creek as well as evaluating potential corporate or asset-based acquisitions. Balance sheet strength is a clear component of our 2015 strategy and we anticipate that the continued weakness of commodity prices may present opportunities to acquire quality assets at attractive economics. 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. We have started to see the effects of improvements made to our cost structure within the organization in the first half of 2015 and will continue to see further improvements as we optimize our operational efficiencies at Birley/Umbach. We have revised our 2015 capital program from $45.0 million to $55.0 million to accelerate a facility expansion and a completions program at Birley/Umbach, BC, while deferring our originally planned drilling and completions work at Gold Creek, Alberta. By accelerating the timing of our capital activity at Birley/Umbach from early 2016 to the second half of 2015, we anticipate accelerating the realization of operational and seasonal cost efficiencies and taking advantage of lower industry service costs. Expanding our Birley/Umbach facility will allow us to be well positioned for the expected increase in production volumes from our 2016 drilling program. We plan to fund this increased 2015 capital program through our existing net surplus position which included $50.7 million of cash on hand at June 30, 2015.

Our updated guidance, based on our revised 2015 capital program is set forth below:

($ millions, except boe/d)	2015 Previous Guidance (1)	2015 Revised Guidance (2)
Average production (boe/d)	6,600-7,000	6,600-7,000
Exit production (boe/d)	6,800-7,100	7,600-7,900
General & administrative expense	$ 10.5-11.0	$ 9.6-10.1
Production & operating expense	$ 41.0-43.0	$ 41.0-43.0
Funds from operations	$ 10.0-11.0	$ 9.0-10.0
Net surplus	$ 34.0-35.0	$ 22.0-24.0
Capital expenditures	$ 45.0	$ 55.0

(1) Pricing assumptions: Canadian crude oil of $54.03/bbl; Canadian natural gas of $3.19/mcf.
(2) Revised pricing assumptions: Canadian crude oil of $55.50/bbl; Canadian natural gas of $2.80/mcf.

Quarterly Information from Continuing Operations

Summarized information by quarter for the two years ended June 30, 2015, appears below:

	Jun. 30 2015	Mar. 31 2015	Dec. 31 2014	Sep. 30 2014	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013
CONTINUING CANADIAN OPERATIONS								
Production Volumes								
Crude oil (bbl/d)	**1,284**	1,485	1,981	1,823	2,267	2,084	1,840	1,853
Natural gas liquids (boe/d)	**604**	682	778	678	715	950	722	753
Natural gas (mcf/d)	**25,290**	33,007	34,879	29,028	29,570	29,364	32,287	34,563
Average daily production (boe/d)	**6,103**	7,668	8,572	7,339	7,911	7,928	7,943	8,367
Sales Prices								
Average oil price ($/bbl)	**$ 62.90**	$ 49.03	$ 70.84	$ 93.10	$ 101.01	$ 96.41	$ 81.18	$ 97.53
Average natural gas liquids price ($/boe)	**$ 41.06**	$ 36.47	$ 48.05	$ 64.71	$ 72.06	$ 74.10	$ 63.74	$ 62.36
Average natural gas price ($/mcf)	**$ 2.50**	$ 2.65	$ 3.57	$ 4.11	$ 4.89	$ 6.01	$ 3.57	$ 2.55
Netback (1)								
Average commodity pricing ($/boe)	**$ 27.67**	$ 24.15	$ 35.26	$ 45.37	$ 53.75	$ 56.50	$ 39.09	$ 37.76
Royalties ($/boe)	**$ (0.78)**	$ (2.07)	$ (4.74)	$ (6.90)	$ (8.47)	$ (6.01)	$ (4.80)	$ (3.53)
Net production expenses ($/boe) (1)	**$ (18.36)**	$ (17.04)	$ (18.89)	$ (17.44)	$ (17.06)	$ (16.91)	$ (15.83)	$ (16.42)
G&A expense ($/boe)	**$ (3.70)**	$ (4.00)	$ (4.26)	$ (4.32)	$ (4.30)	$ (6.46)	$ (3.47)	$ (1.71)
Netback ($/boe) (1)	**$ 4.83**	$ 1.04	$ 7.37	$ 16.71	$ 23.92	$ 27.12	$ 14.99	$ 16.10
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	**$ 14,934**	$ 15,240	$ 24,065	$ 25,972	$ 32,595	$ 36,029	$ 25,055	$ 26,347
Funds from operations (2)	**$ 2,995**	$ 1,220	$ 6,069	$ 9,693	$ 14,798	$ 17,596	$ 8,786	$ 12,213
Per share - basic and diluted ($/share)	**$ 0.01**	$ 0.01	$ 0.03	$ 0.05	$ 0.07	$ 0.08	$ 0.04	$ 0.06
Net (loss) income from continuing operations (3)	**$ (5,822)**	$ 8,189	$ (58,311)	$ 3,696	$ 3,531	$ 410	$ (10,151)	$ (316)
Per share - basic and diluted ($/share)	**$ (0.03)**	$ 0.04	$ (0.27)	$ 0.02	$ 0.02	$ -	$ (0.05)	$ -
Net (loss) income (3)(4)(5)	**$ (5,822)**	$ 8,189	$ (60,348)	$ 11,472	$ 4,391	$ 6,085	$ (39,002)	$ 3,812
Per share - basic and diluted ($/share)	**$ (0.03)**	$ 0.04	$ (0.28)	$ 0.05	$ 0.02	$ 0.03	$ (0.18)	$ 0.02
Capital expenditures and business combination	**$ 4,921**	$ 22,093	$ 39,671	$ 14,301	$ 18,998	$ 23,614	$ 9,854	$ 10,014
Net debt (surplus) (1) (6)	**$ (46,705)**	$ (48,596)	$ (28,788)	$ (35,870)	$ 80,536	$ 74,390	$ 61,849	$ 65,105
Total assets (6)	**$ 414,280**	$ 431,085	$ 434,318	$ 472,241	$ 589,515	$ 604,419	$ 555,341	$ 593,192
Common Shares (thousands)								
Weighted average during period - basic	**215,089**	215,083	215,081	214,895	214,226	214,188	214,188	214,188
Weighted average during period - diluted	**215,089**	215,112	215,081	216,773	215,814	214,245	214,188	214,188
Outstanding at period end	**215,236**	215,083	215,082	215,079	214,674	214,188	214,188	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) Refer to the sections "Funds from Operations" and "Additional GAAP Measures" contained within this MD&A.

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

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

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

(6) 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 two quarters of 2015 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 of 2015, 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 two quarters of 2015. 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 April 1, 2015 and ended on June 30, 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

Additional GAAP Measures

This MD&A contains the additional GAAP measure of “funds from operations”, which 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. 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. 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.

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.

- Working capital excluding mark-to-market derivative contracts 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 debt. 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: that we will remain undrawn on our credit facility through the balance of 2015, our forecasted production and operating costs for the year ended 2015, our forecasted G&A costs for the year ended 2015, 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 revised 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 updated guidance for 2015 as set forth 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 revised 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.

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.