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 nine months ended September 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 nine months ended September 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 November 9, 2015.

The term "third quarter" and "year to date" or similar terms are used throughout this document and refer to the three and nine months ended September 30, 2015, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three and nine months ended September 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) nine months ended September 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 periods' 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. With a modest improvement in commodity prices, these assets provide the opportunity for substantial growth and long-term profitable development.

We are incorporated under the laws of the Province of Alberta, Canada. Our common shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "CKE". Our head office and principal address is Suite 1000, 517 – 10th Avenue S.W., Calgary, Alberta, Canada T2R 0A8.

Discontinued Operations

On August 19, 2014, our wholly-owned subsidiary, Storm Ventures International (BVI) Limited ("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 September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
CONTINUING CANADIAN OPERATIONS (1) (2)				
Production				
Crude oil (bbl/d)	**1,065**	1,823	**1,276**	2,057
Natural gas liquids (boe/d)	**395**	678	**559**	780
Natural gas (mcf/d)	**20,641**	29,028	**26,268**	29,320
Average daily production (boe/d)	**4,900**	7,339	**6,214**	7,724
Sales Prices				
Average oil price ($/bbl)	**$ 51.34**	$ 93.10	**$ 54.33**	$ 97.11
Average natural gas liquids price ($/boe)	**$ 31.68**	$ 64.71	**$ 36.98**	$ 70.73
Average natural gas price ($/mcf)	**$ 2.56**	$ 4.11	**$ 2.58**	$ 5.00
Netback (3)				
Average commodity pricing ($/boe)	**$ 24.48**	$ 45.37	**$ 25.39**	$ 52.00
Royalties ($/boe)	**$ (1.13)**	$ (6.90)	**$ (1.40)**	$ (7.14)
Net production expenses ($/boe) (3)	**$ (12.49)**	$ (17.44)	**$ (16.29)**	$ (17.13)
G&A expense ($/boe)	**$ (4.39)**	$ (4.32)	**$ (4.01)**	$ (5.04)
Netback ($/boe) (3)	**$ 6.47**	$ 16.71	**$ 3.69**	$ 22.69
Wells Drilled (net)				
Oil	**-**	1.26	**-**	4.52
Gas	**-**	0.75	**2.75**	1.87
Disposal/injection	**-**	0.37	**-**	0.37
Total wells drilled (net)	**-**	2.38	**2.75**	6.76
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 10,527**	$ 25,972	**$ 40,701**	$ 94,597
Funds from operations (4)	**$ 3,299**	$ 9,693	**$ 7,517**	$ 42,089
Per share - basic and diluted ($/share)	**$ 0.02**	$ 0.05	**$ 0.03**	$ 0.20
Net (loss) income from continuing operations	**$ (80,669)**	$ 3,696	**$ (78,303)**	$ 7,369
Per share - basic and diluted ($/share)	**$ (0.37)**	$ 0.02	**$ (0.36)**	$ 0.04
Net (loss) income (5)	**$ (80,669)**	$ 11,472	**$ (78,303)**	$ 21,948
Per share - basic and diluted ($/share)	**$ (0.37)**	$ 0.05	**$ (0.36)**	$ 0.10
Capital expenditures	**$ 7,313**	$ 14,301	**$ 34,327**	$ 56,913
Net debt (surplus) (3)	**$ (41,181)**	$ (35,870)	**$ (41,181)**	$ (35,870)
Total assets (5)	**$ 333,036**	$ 472,241	**$ 333,036**	$ 472,241
Common Shares (thousands)				
Weighted average during period				
- basic	**215,274**	214,895	**215,150**	214,439
- diluted	**215,274**	216,773	**215,150**	215,590
Outstanding at period end	**215,328**	215,079	**215,328**	215,079

(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, up to the date of their sale on August 19, 2014.

Comparison to Guidance

Ongoing pipeline service restrictions and reduced system capacity have caused a severe negative impact on northeastern British Columbia natural gas prices on the Spectra ("Station 2 pricing") and Alliance ("CREC pricing") pipeline systems. It is estimated that these service restrictions should be largely resolved by mid-November 2015. We have responded to this depressed pricing by temporarily shutting in production volumes which are not tied to firm processing or transportation commitments with approximately 16.3 mmcf/d of natural gas production shut-in during September. As a result, assuming this shut-in production is restored by mid-November, we estimate that our 2015 average production will be approximately 5,700 – 5,900 boe/d down from 6,600 – 7,000 boe/d.

During the third quarter of 2015, we completed three wells (2.75 net) at Birley/Umbach which were all drilled in previous quarters. The costs of these three wells represent a reduction of between 38% and 42% compared to our average drill, complete, equip and tie-in costs of $7.6 million per well in 2014 at Birley/Umbach. As a result of these realized cost savings, we have reduced our 2015 capital budget from $55 million to $49 million without delaying the installation of the facility expansion at Birley/Umbach.

Petroleum and Natural Gas Production Volumes

	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Crude oil (bbl/d)	**1,065**	1,823	**1,276**	2,057
Natural gas liquids (boe/d)	**395**	678	**559**	780
Natural gas (mcf/d)	**20,641**	29,028	**26,268**	29,320
Total (boe/d)	**4,900**	7,339	**6,214**	7,724

Total Production Volumes

Our production volumes for the current reporting periods decreased by 2,439 boe/d and 1,510 boe/d 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. Scheduled third party plant restrictions and turnarounds also reduced our year-to-date production. In addition, ongoing pipeline service restrictions and reduced system capacity have caused a severe negative impact on natural gas prices at Station 2 on the Spectra pipeline and CREC pricing on the Alliance pipeline system. It is estimated that these service restrictions should be largely resolved by mid-November 2015. We have responded to this depressed pricing by temporarily shutting in production volumes which are not tied to firm processing or transportation commitments with approximately 16.3 mmcf/d of natural gas production shut-in during September. Prior to September, we had also shut-in another 600 boe/d in response to lower commodity prices.

Partially offsetting these decreases was approximately 435 boe/d and 660 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. Production from both of these properties was also negatively affected by temporary shut-ins as we responded to depressed pricing caused by pipeline capacity constraints. Late in 2014, we also acquired a 1,200 boe/d natural gas property in the Birley/Umbach area. This 100% owned and operated acquisition included key infrastructure which we believe strategic to the long term delivery of volumes from this area.

As previously mentioned, during the third quarter of 2015, we completed three wells (2.75 net) at Birley/Umbach, which were all drilled in previous quarters. All three wells are currently shut-in in order to equip and tie-in the wells for production. This production is expected to commence in the first quarter of 2016 upon completion of our previously announced facility expansion at Birley/Umbach, which is currently underway. The first stage of the expansion of this compression facility from 9 mmcf/d to 34 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. Partially offsetting these decreases were 6,600 mcf/d and 8,100 mcf/d of natural gas production associated with both last year's property acquisitions and our successful drilling program in the Birley/Umbach area, respectively.

During September, pipeline service restrictions and reduced system capacity in northeastern BC forced us to partially shut-in both properties.

As a result of the disposition of the Gilby properties and production constraints on our Montney liquids rich play we are reporting decreases in the current reporting periods' NGL production of approximately 380 boe/d and 220 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 760 bbl/d and 780 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 September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	**2015**	2014	**2015**	2014
Oil sales	**$ 5,030**	$ 15,614	**$ 18,931**	$ 54,541
$/bbl	**51.34**	93.10	**54.33**	97.11
Natural gas liquids sales	**$ 1,151**	$ 4,034	**$ 5,646**	$ 15,057
$/boe	**31.68**	64.71	**36.98**	70.73
Natural gas sales	**$ 4,855**	$ 10,985	**$ 18,494**	$ 40,045
$/mcf	**2.56**	4.11	**2.58**	5.00
Petroleum and natural gas revenue	**$ 11,036**	$ 30,633	**$ 43,071**	$ 109,643
$/boe	**24.48**	45.37	**25.39**	52.00

Our petroleum and natural gas revenues of $11.0 million and $43.1 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 decrease in our realized commodity pricing was mostly due to lower benchmarks whose decline accelerated starting during the fourth quarter of 2014. Our ratio of the comparatively higher priced crude oil sales, relative to total sales volumes, decreased during the current reporting periods to 22% and 21% from 25% 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 September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Crude oil Canadian light sweet (1) ($/bbl)	**$ 55.10**	$ 97.71	**$ 59.09**	$ 100.53
Natural gas liquids WTI (2) ($US/bbl)	**$ 46.43**	$ 97.17	**$ 51.00**	$ 99.61
Natural gas AECO gas (3) ($/mcf)	**$ 2.72**	$ 4.08	**$ 2.58**	$ 4.88

(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 more than 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 $31.68/boe and $36.98/boe decreased compared to $64.71/boe and $70.73/boe for the same periods of 2014. The ratio of our NGL price relative to Canadian light sweet oil was 58% and 63% for the current reporting periods compared to 66% and 70% for comparative periods of 2014. The decreases in this ratio was due to a lower average price for propane which fell by 93% and 90% during the current reporting periods compared to the same periods of 2014.

Natural Gas Pricing

Our realized natural gas price of $2.56/mcf and $2.58/mcf for the current reporting periods decreased from $4.11/mcf and $5.00/mcf for the same periods of 2014. These decreases were due to both the lower AECO benchmark in addition to Station 2 and CREC pricing. During the current reporting periods, a portion of our natural gas production was sold at these other hub benchmark prices which experienced pricing volatility. The spot pricing volatility is a consequence of ongoing pipeline service restrictions and reduced system capacity which forced us and other producers who had firm delivery volumes to divert production to other third party pipelines, or curtail delivery. Various pipeline restrictions caused, and continue to cause, industry volume increases on these third party pipelines and correspondingly, downward price pressures at these other sales point hubs.

Royalties

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Royalties	**$ 509**	$ 4,661	**$ 2,370**	$ 15,046
Per sales ($/boe)	**$ 1.13**	$ 6.90	**$ 1.40**	$ 7.14
Percent of revenues (%)	**5**	15	**6**	14

For the current reporting periods, our royalties decreased on an overall basis, per boe and as a percentage of revenue, compared to the same periods of 2014. These decreases partially resulted from adjustments to our gas cost allowance. In addition, the decreases in our royalties on an overall and on a boe basis resulted from lower realized prices in the current reporting periods compared to the same periods of 2014. As a 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 the 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 of 2015, 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, 71% and 67% 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 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 September 30		Nine months ended September 30	
($ thousands)	**2015**	2014	**2015**	2014
Realized (gains) losses on derivative contracts	**$ (391)**	$ 731	**$ (1,132)**	$ 3,601
Unrealized losses (gains) on derivative contracts	**406**	(2,440)	**1,090**	(363)
Total	**$ 15**	$ (1,709)	**$ (42)**	$ 3,238

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 $2.76/mcf and $2.74/mcf compared to our reported prices of $2.56/mcf and $2.58/mcf.

Our unrealized losses for the current reporting periods resulted from the AECO derivative contract's unrealized fair value becoming realized over its term. As at September 30, 2015, this commodity price contract had an estimated current asset fair value of $0.4 million with the following terms:

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

Production and Operating Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Production & operating	**$ 6,243**	$ 13,451	**$ 30,099**	$ 40,582
Less:				
Processing & gathering revenues	**(610)**	(1,676)	**(2,466)**	(4,460)
Net production & operating expense (1)	**$ 5,633**	$ 11,775	**$ 27,633**	$ 36,122
Per sales net production & operating expenses ($/boe) (1)	**$ 12.49**	$ 17.44	**$ 16.29**	$ 17.13
Per sales production & operating expenses ($/boe)	**$ 13.85**	$ 19.92	**$ 17.74**	$ 19.25

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

The current reporting periods' production and operating expenses of $6.2 million and $30.1 million decreased compared to the same periods of 2014. These decreases partially resulted from the 2014 and first quarter dispositions of properties at Gilby and Karr, the voluntary shut-in of relatively higher operating cost/lower netback wells and our September response to depressed pricing by temporarily shutting in 16.3 mmcf/d of natural gas production. 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 Hoffard, Pouce Coupe, Marten Hills, Rainbow, Whitecourt, Enchant and Rigel properties.

On a per boe basis, production and operating costs in the current reporting periods decreased compared to the same periods of 2014 due to the effect of voluntarily shutting in higher cost/lower netback wells, temporary shut-ins, which included our recently developed properties at Birley/Umbach, which also has higher associated production costs in addition to other implemented cost saving initiatives. A review of these realized cost savings allowed us to re-evaluate and lower our previously reported operating costs.

In response to the recent decline in commodity pricing we are targeting significant cost reductions. 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 September 30		Nine months ended September 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
G&A expense	**$ 1,981**	$ 2,916	**$ 6,795**	$ 10,624
Per sales ($/boe)	**$ 4.39**	$ 4.32	**$ 4.01**	$ 5.04

We have continued to focus on improving our G&A cost structure and as a result of cost cutting initiatives have reduced our G&A expense, on an overall basis, during the current reporting periods compared to the same periods of 2014. During the current reporting periods we saw significant reductions as compared to the same periods of 2014. We continue to assess our G&A expenses and make reductions where necessary. For the year to date, this decrease was 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 $6.4 million or $3.76/boe.

On a boe basis, we achieved a decrease during the year to date despite lower production volumes compared to the same period of 2014. Despite a decrease of $0.9 million in G&A expense during the third quarter as compared to the same quarter of 2014, the effect of the temporary September shut-in volumes was an increase in G&A on a boe basis.

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 saved us a combined $0.5 million during the second and third quarters. During the current reporting periods, our G&A also decreased due to an incremental $0.1 million and $0.3 million related party recovery. For the fourth quarter of 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.

Netback

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

	Three months ended September 30		Nine months ended September 30	
Per sales ($/boe)	**2015**	2014	**2015**	2014
Realized sales price	**$ 24.48**	$ 45.37	**$ 25.39**	$ 52.00
Less:				
Royalties	**(1.13)**	(6.90)	**(1.40)**	(7.14)
Net production expense (1)	**(12.49)**	(17.44)	**(16.29)**	(17.13)
G&A expense	**(4.39)**	(4.32)	**(4.01)**	(5.04)
Netback (1)	**$ 6.47**	$ 16.71	**$ 3.69**	$ 22.69

(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 higher oil weighted 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 net production expenses and royalties on a boe basis. The shut-in of relatively higher operating cost properties has decreased our weighted average net production expense on a boe basis. We are also reporting lower royalties on a boe basis due to the effect of lower commodity pricing. Our year to date G&A on a boe basis was also lower and 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 in the fourth quarter of 2015 to reduce our operating and G&A costs.

Exploration and Evaluation Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2015**	2014	**2015**	2014
Exploration and evaluation expenditures	**$ -**	$ 478	**$ 917**	$ 1,063

Exploration and evaluation expense reported during the year to date and comparative periods was due to pre-licensing evaluation and other exploratory costs.

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

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Depletion, depreciation and amortization	**$ 7,458**	$ 11,503	**$ 26,948**	$ 36,136
Per sales ($/boe)	**$ 16.54**	$ 17.04	**$ 15.89**	$ 17.14

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. Our year to date decreases in both 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

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Impairment of development & production assets	**$ 75,000**	$ -	**$ 75,000**	$ -

We identified triggers indicating impairment of our CGUs. These triggers resulted from the reduction in both short and long-term forward Canadian petroleum and natural gas prices. We reported impairment in all of our CGUs for the year ended December 31, 2014. Upon reporting these previous impairment expenses, each CGU’s carrying value approximated its recoverable value. As at September 30, 2015, our testing of each of our CGU’s recoverable value relative to its carrying values revealed an impairment charge totalling $75.0 million as reported in the current reporting periods with impairment being recorded in each of our three CGUs. As at September 30, 2015, each CGU’s recoverable value was estimated using an internally prepared value in use calculation based on expected future cash flows anticipated to be produced from proved plus probable reserves, using an average discount rate of 10% to 15%, depending on the category of reserves, and forward commodity price estimates. We updated our most recent value-in-use measure used in our impairment test for current year-to-date activities. This included production. However, the overall decrease in our most recent measure of value-in-use is attributable to lower forward commodity pricing. This update did not identify any performance issues at our Birley/Umbach property. Once our Birley/Umbach compressor capacity expansion is completed, we will include additional proved and probable reserves through future well locations.

A five percent decrease in the forward commodity price estimate or a one percent increase in the applied discount rate, as determined for each CGU, would have resulted in an additional impairment charge totalling approximately $19.0 million and $4.0 million, respectively. The impairment tests as carried out at September 30, 2015 and December 31, 2014 were based on the following forward price estimates:

As at September 30, 2015	**Canadian Light Sweet Crude ($/bbl) (1) (2)**	**AECO Gas ($/mmbtu) (1) (3)**
2015 (3 months)	$ 60.80	$ 2.90
2016	$ 67.40	$ 3.35
2017	$ 73.40	$ 3.65
2018	$ 78.10	$ 3.85
2019	$ 80.90	$ 4.00
Thereafter	2%/yr	2%/yr

(1) Source: McDaniel & Associates Consultants Ltd. price forecast, effective October 1, 2015.
(2) Central market point for Canadian crude oil.
(3) Central market point for Canadian natural gas.

Gains on Disposition of Properties

	Three months ended September 30		**Nine months ended September 30**	
($ thousands)	**2015**	2014	**2015**	2014
Losses (Gains) on disposition of properties	**$ 6**	$ (2,754)	**$ (21,787)**	$ (2,920)

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 was completed on January 6, 2015. At December 31, 2014, the Karr properties were classified as held for sale. This classification included carrying values of $23.1 million for both exploration and evaluation assets and D&P Assets and $0.8 million for decommissioning obligations.

During the year to date, we participated in one disposition and 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 total year to date reported gains of $21.8 million from property dispositions compared to $2.9 million for the same period of 2014.

Share-Based Compensation

	Three months ended September 30		**Nine months ended September 30**	
($ thousands)	**2015**	2014	**2015**	2014
Share-based compensation	**$ 722**	$ 258	**$ 1,771**	$ 561

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

Bad Debt Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2015**	2014	**2015**	2014
Bad debt expense	**$ -**	$ 100	**$ 554**	$ 165

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 September 30		Nine months ended September 30	
($ thousands)	**2015**	2014	**2015**	2014
Foreign exchange gains & other	**$ (251)**	$ (2,079)	**$ (541)**	$ (2,380)

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

Financing Expenses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2015**	2014	**2015**	2014
Interest and financing charges (income)	**$ 6**	$ 912	**$ (109)**	$ 2,503
Amortization of deferred financing costs	**-**	195	**-**	343
Accretion of decommissioning obligation	**626**	681	**1,865**	2,031
Total	**$ 632**	$ 1,788	**$ 1,756**	$ 4,877

Interest and financing income of $0.1 million for the year to date includes interest income from our cash deposits of $46.2 million at September 30, 2015, as partially offset by standby fees on our credit facility. The interest income we receive on our cash deposits is competitive to other short-term liquid investments. For the first half of 2015, the standby fees were based on a credit facility availability of $125.0 million. 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. This compares to the same periods of 2014 where we incurred interest expense on our average outstanding credit facility balance in addition to standby fees on the available balance. During the third quarter of 2014, we repaid all of the $78.5 million outstanding credit facility balance using the proceeds from the sale of the Discontinued Operations. In conjunction with this repayment, we accelerated the amortization of the remaining deferred financing costs.

The accretion charges during the current reporting periods had a modest decrease compared to the same periods of 2014. These decreases resulted from applying a lower 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 September 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 September 30		Nine months ended September 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Weighted average shares outstanding - basic (thousands)	**215,274**	214,895	**215,150**	214,439
awards (thousands)	**-**	1,878	**-**	1,151
Weighted average shares outstanding - diluted (thousands)	**215,274**	216,773	**215,150**	215,590
Net (loss) income from continuing operations	**$ (80,669)**	$ 3,696	**$ (78,303)**	$ 7,639
Per share - basic & diluted ($/share)	**$ (0.37)**	$ 0.02	**$ (0.36)**	$ 0.04
Net income from discontinued operations	**$ -**	$ 7,776	**$ -**	$ 14,309
Per share - basic & diluted ($/share)	**$ -**	$ 0.03	**$ -**	$ 0.06
Net (loss) income	**$ (80,669)**	$ 11,472	**$ (78,303)**	$ 21,948
Per share - basic & diluted ($/share)	**$ (0.37)**	$ 0.05	**$ (0.36)**	$ 0.10
Comprehensive (loss) income	**$ (80,669)**	$ 5,049	**$ (78,303)**	$ 15,707
Per share - basic and diluted ($/share)	**$ (0.37)**	$ 0.02	**$ (0.36)**	$ 0.07

During the current reporting periods we reported net losses from continuing operations compared to net income during the same periods of 2014. The net losses for the current reporting periods were caused by recognizing $75.0 million of impairment expense resulting from both lower short and long-term forward curve commodity prices. Further contributing to these net losses was lower petroleum and natural gas revenues due to the effect of both lower sales volumes and realized commodity prices. Partially offsetting these decreases were lower charges for operating, royalties, G&A, depletion and financing costs in addition to year to date gains on both property dispositions and realized derivative transactions.

Our net income for the comparative periods also included the financial results from the Discontinued Operations. For these periods, in addition to including net income, our comprehensive income also included foreign exchange gains on the translation of the US dollar denominated Discontinued Operations as reported in Canadian dollars. On disposition of these operations, we moved $9.5 million of accumulated other comprehensive income to income from discontinued operations. The net effect of this transfer was nil for our reported comprehensive income although it did offset the effect of the translation gains. As previously mentioned, our Discontinued Operations were sold on August 19, 2014.

Capital Resources, Capital Expenditures and Liquidity

As announced on October 16, 2015, we have revised our 2015 capital program from $55.0 million to $49.0 million due to cost savings realized at Birley/Umbach on the completion of the three wells (2.75 net) in the third quarter. The average drill, complete, equip and tie-in costs for a well at Birley/Umbach was approximately $7.6 million per well in 2014, bringing our total to $22.8 million on a three well program. During 2015, we were able to drill and complete the three wells (2.75 net) including an estimate for equipping and tie-in costs for $16.7 million for savings of approximately $6.0 million. This decrease in the capital budget will not delay our installation of the first phase of a facility expansion targeting our Montney resource at Birley/Umbach, BC. 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 have deferred our originally planned drilling and completions work at Gold Creek, Alberta.

Late in the fourth quarter, we will be renewing our credit facility which currently is undrawn with an availability of $75.0 million. We are aware that forward commodity prices have decreased since we last renewed this facility's availability. Our remaining 2015 capital program is anticipated to be funded through our existing net surplus position which included $46.2 million of cash on hand at September 30, 2015 and our funds from operations.

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

Funds from Operations

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2015**	2014	**2015**	2014
Funds from operations (1)	**$ 3,299**	$ 9,693	**$ 7,517**	$ 42,089
Per share - basic and diluted	**$ 0.02**	$ 0.05	**$ 0.03**	$ 0.20
Per sales ($/boe)	**$ 7.32**	$ 14.36	**$ 4.43**	$ 19.96

(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 $3.3 million and $7.5 million compared to $9.7 million and $42.1 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 lower proportions of crude oil relative to total production volumes. The decreases in the sales volumes resulted from pipeline service restrictions and reduced system capacity throughout the year, scheduled plant restrictions and turnarounds, the Karr and Gilby property dispositions, voluntary and temporary shut-ins and capacity constraints at our Montney liquids rich development. Partially offsetting these decreases were realized gains from our derivative contract and lower cash costs. The most notable cash cost decreases were for operating, G&A and cash financing charges. Operating charges decreased $7.2 million and $10.5 million during the current reporting periods due to lower production volumes and cost saving initiatives. G&A costs decreased $0.9 million and $3.8 million during the current reporting periods due to headcount reductions of both personnel and consultants, implemented cost saving initiatives, including a reduced temporary work week and a higher related party recovery. For the current reporting periods, interest 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 $2.6 million compared to the same periods of 2014 when we had outstanding debt with associated interest charges. As mentioned, we also had realized gains in the current reporting periods from our derivative contract which increased funds from operations by $1.1 million and $4.7 million compared to losses on similar contracts for the same periods of 2014. Our funds from operations is higher than our netback, on a boe basis, because the cash finance income and the realized gain on our derivative contract are both included in the funds from operations, whereas they are excluded from our netback.

Credit Facility

	September 30 2015	December 31 2014
($ thousands)		
Long-term debt	**$ -**	$ -
Less:		
Working capital (1)	**(41,181)**	(28,788)
Net debt (surplus) (2)	**$ (41,181)**	$ (28,788)

(1) Excludes mark-to-market derivative contracts and assets and liabilities held for sale.

(2) 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 September 30, 2015. We had a net surplus of $41.2 million at September 30, 2015, compared to $28.8 million at December 31, 2014. This positive change of $12.4 million was due to the proceeds of $42.9 million received mostly from the Karr property disposition and $7.5 million from funds from operations which excluded $0.8 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 $38.8 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. The next redetermination is scheduled to be completed on or before November 30, 2015. At September 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 September 30		Nine months ended September 30	
($ thousands)	**2015**	2014	**2015**	2014
Land and lease	**$ 457**	$ 132	**$ 586**	$ 14,334
Drilling and completions	**4,789**	10,559	**17,453**	30,282
Facilities and equipment	**1,668**	3,206	**15,272**	11,072
Field expenditures	**6,914**	13,897	**33,311**	55,688
Capitalized G&A	**399**	309	**956**	851
Furniture and equipment	**-**	95	**60**	374
Total	**$ 7,313**	$ 14,301	**$ 34,327**	$ 56,913
Business combination and other price adjustments	**$ 898**	$ -	**$ 898**	$ -
Proceeds from dispositions	**$ -**	$ 5,414	**$ 42,935**	$ 5,446

During the third quarter of 2015, we completed three (2.75 net) Montney wells at Birley/Umbach that were drilled in previous quarters. Our completion costs were down significantly from the prior three completions due to multi-well program efficiencies, significant effort by the operations group in getting lower service costs, and management's decision not to run coiled tubing clean-outs on any of the new wells. These completed wells were all set up for 18 stage ball drop completions. Two of the wells had all stages pumped successfully while the other well had one stage that was not initiated and two more stages that had to be called prior to getting all 65 tons into the formation.

We expect to complete the majority of the first phase expansion of the compression facility in our Birley/Umbach area during the fourth quarter of 2015. During the current reporting periods, we have purchased the compressor's equipment. This first expansion will increase our facility's capacity from 9 mmcf/d to 34 mmcf/d. The additional throughput capacity resulting from this facility expansion will enable us to bring a previously completed well back on-stream in addition to the three wells (2.75 net) completed in the third quarter.

Rationalization of Properties

We may from time to time, dispose of properties so that we can focus on the immediate development of Montney liquids rich natural gas on our Birley/Umbach BC properties and in the near future our Montney and Dunvegan light crude oil in Grande Prairie, Alberta. As a result, during the year to date we completed the sale of petroleum and natural gas properties including undeveloped lands located in the Karr 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.

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, in addition to the carrying value for other insignificant dispositions, 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 September 30, 2015, an estimate for these indemnifications in addition to unpaid transaction costs totaled $2.8 million. During the year to date we paid $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 September 30, 2015 and December 31, 2014, our provision remained unchanged at $106.7 million. For the year to date, a reported decrease resulted from decommissioning obligation and other expenditures of $1.9 million (same period of 2014 - $1.8 million) and sold decommissioning obligations of $0.3 million (same period of 2014 - $1.5 million). Offsetting this decrease were additions of $0.3 million related to our first quarter drilling program and $1.9 million of accretion charges (same periods of 2014 - $0.4 million and $1.4 million respectively). The recognized accretion charges reflect the increase in the decommissioning obligation associated with the passage of time.

As at September 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 September 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:

	September 30 2015	December 31 2014
Common shares outstanding	**215,327,986**	215,082,199
Share options	**8,575,281**	10,529,675
Restricted awards	**1,144,652**	206,590
Performance awards	**1,066,161**	244,375

As at November 9, 2015, we had 215,327,986 common shares, 7,445,001 share options, 1,143,542 restricted awards and 1,065,606 performance awards outstanding.

Outlook

In our October 16, 2015 news release, we updated our 2015 capital budget to reflect the cost saving that we have realized related to the drilling and completion of wells at Birley/Umbach and announced a reduction in our 2015 volumes guidance due to the temporary, voluntary shut-in of wells in response the decrease in the northeastern British Columbia natural gas prices. As previously disclosed, our updated 2015 capital budget is $49 million and we estimate that our 2015 average production will be approximately 5,700 – 5,900 boe/d, assuming our approximately 16.3 mmcf/d of shut-in natural gas production is restored by mid-November 2015.

For 2016 we remain committed to focusing on our cost and capital management as well as maintaining our strong balance sheet.

Quarterly Information from Continuing Operations

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

	Sept. 30 2015	Jun. 30 2015	Mar. 31 2015	Dec. 31 2014	Sep. 30 2014	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013
CONTINUING CANADIAN OPERATIONS								
Production Volumes								
Crude oil (bbl/d)	**1,065**	1,284	1,485	1,981	1,823	2,267	2,084	1,840
Natural gas liquids (boe/d)	**395**	604	682	778	678	715	950	722
Natural gas (mcf/d)	**20,641**	25,290	33,007	34,879	29,028	29,570	29,364	32,287
Average daily production (boe/d)	**4,900**	6,103	7,668	8,572	7,339	7,911	7,928	7,943
Sales Prices								
Average oil price ($/bbl)	**$ 51.34**	$ 62.90	$ 49.03	$ 70.84	$ 93.10	$ 101.01	$ 96.41	$ 81.18
Average natural gas liquids price ($/boe)	**$ 31.68**	$ 41.06	$ 36.47	$ 48.05	$ 64.71	$ 72.06	$ 74.10	$ 63.74
Average natural gas price ($/mcf)	**$ 2.56**	$ 2.50	$ 2.65	$ 3.57	$ 4.11	$ 4.89	$ 6.01	$ 3.57
Netback (1)								
Average commodity pricing ($/boe)	**$ 24.48**	$ 27.67	$ 24.15	$ 35.26	$ 45.37	$ 53.75	$ 56.50	$ 39.09
Royalties ($/boe)	**$ (1.13)**	$ (0.78)	$ (2.07)	$ (4.74)	$ (6.90)	$ (8.47)	$ (6.01)	$ (4.80)
Net production expenses ($/boe) (1)	**$ (12.49)**	$ (18.36)	$ (17.04)	$ (18.89)	$ (17.44)	$ (17.06)	$ (16.91)	$ (15.83)
G&A expense ($/boe)	**$ (4.39)**	$ (3.70)	$ (4.00)	$ (4.26)	$ (4.32)	$ (4.30)	$ (6.46)	$ (3.47)
Netback ($/boe) (1)	**$ 6.47**	$ 4.83	$ 1.04	$ 7.37	$ 16.71	$ 23.92	$ 27.12	$ 14.99
Wells Drilled (net)								
Oil	**-**	-	-	1.62	1.26	-	3.26	1.65
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
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of	**$ 10,527**	$ 14,934	$ 15,240	$ 24,065	$ 25,972	$ 32,595	$ 36,029	$ 25,055
Funds from operations (2)	**$ 3,299**	$ 2,995	$ 1,220	$ 6,069	$ 9,693	$ 14,798	$ 17,596	$ 8,786
Per share - basic and diluted ($/share)	**$ 0.02**	$ 0.01	$ 0.01	$ 0.03	$ 0.05	$ 0.07	$ 0.08	$ 0.04
Net (loss) income from continuing operations	**$ (80,669)**	$ (5,822)	$ 8,189	$ (58,311)	$ 3,696	$ 3,531	$ 410	$ (10,151)
Per share - basic and diluted ($/share)	**$ (0.37)**	$ (0.03)	$ 0.04	$ (0.27)	$ 0.02	$ 0.02	$ -	$ (0.05)
Net (loss) income (3)(4)(5)	**$ (80,669)**	$ (5,822)	$ 8,189	$ (60,348)	$ 11,472	$ 4,391	$ 6,085	$ (39,002)
Per share - basic and diluted ($/share)	**$ (0.37)**	$ (0.03)	$ 0.04	$ (0.28)	$ 0.05	$ 0.02	$ 0.03	$ (0.18)
Capital expenditures	**$ 7,313**	$ 4,921	$ 22,093	$ 23,821	$ 14,301	$ 18,998	$ 23,614	$ 9,854
Net debt (surplus) (1) (6)	**$ (41,181)**	$ (46,705)	$ (48,596)	$ (28,788)	$ (35,870)	$ 80,536	$ 74,390	$ 61,849
Total assets (6)	**$ 333,036**	$ 414,280	$ 431,085	$ 434,318	$ 472,241	$ 589,515	$ 604,419	$ 555,341
Common Shares (thousands)								
Weighted average during period - basic	**215,274**	215,089	215,083	215,081	214,895	214,226	214,188	214,188
Weighted average during period - diluted	**215,274**	215,089	215,112	215,081	216,773	215,814	214,245	214,188
Outstanding at period end	**215,328**	215,236	215,083	215,082	215,079	214,674	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, $63.5 million and $75.0 million in impairment charges against properties for the three months ended December 31, 2013 and 2014 and September 30, 2015, 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 September 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 quarter of 2015, production volumes decreased reflecting the impact of significant dispositions in our Gilby and Karr areas and have since fallen in subsequent quarters due to voluntary shut-ins of properties with high operating costs/low netbacks and ongoing pipeline service restrictions and reduced system capacity. Our realized commodity prices and natural gas revenue, net of royalties have mostly trended with the Canadian Light Sweet and AECO benchmarks which generally increased until mid-2014 when they began to decrease with significantly lower benchmark pricing observed in the fourth quarter of 2014 and the first three quarters of 2015. Changes in our petroleum and natural gas revenues, net of royalties and funds from operations have generally trended with benchmark commodity prices. 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 July 1, 2015 and ended on September 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: the estimated timing that certain pipeline service restrictions and reduced system capacity should be largely resolved, our 2015 average production guidance, the amount of our reduced 2015 capital budget, the timing of the completion of the facility expansion at Birley/Umbach and the increased facility throughput capacity resulting therefrom, the expected timing of the commencement of production from the three recently completed wells at Birley/Umbach, the percentage of our natural gas sales volumes during the year ended 2015 that a price risk contract is expected to secure our received commodity prices on, our forecasted production, operating costs and G&A costs for the year ended 2015, how our remaining 2015 capital program is anticipated to be funded, expectations regarding future reductions in operating and G&A costs and future exploration and development activities and the timing thereof.

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, the continued availability of adequate cash, debt and cash flow to fund our planned expenditures and for the purposes of estimating our reduced 2015 average production we have assumed among other things that our shut-in production will be restored by mid-November. 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. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl (barrel) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Future Oriented Financial Information

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