2014 Management's Discussion and Analysis

Chinook Energy Inc. | 1000, 517 – 10th Avenue S.W. Calgary, Alberta T2R 0A8 TSX:CKE

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. ("our", "we" or "us") for the years ended December 31, 2014 and 2013 and should be read in conjunction with our consolidated financial statements and accompanying notes as at and for the years ended December 31, 2014 and 2013 (the "Financial Statements"). This MD&A is based on information available as at March 9, 2015.

The term "fourth quarter" and "reported year" or similar terms are used throughout this document and refer to the three months and year ended December 31, 2014, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three months and year ended December 31, 2014, in this respective order. The term "same period(s) of 2013" or similar terms are used throughout this document and refer to either the three months or (and) year ended December 31, 2013, in this respective order, depending on the 2014 period under discussion.

Additional Information

Additional information on our company can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com. Our Annual Information Form for the year ended December 31, 2014 will be filed on SEDAR prior to March 31, 2015.

Basis of Presentation

Our Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Our consolidated financial position (the "Balance Sheet") and results of operations include the accounts of our direct subsidiaries all of which are wholly owned. The Balance Sheet for the year ended December 31, 2013 also includes the accounts of our discontinued operations, which were held indirectly in subsidiaries. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per unit amounts or as otherwise noted. Certain financial measures referred to in this MD&A, such as funds from operations (and per share), netback, net debt (surplus) and net production expense, etc., are not prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

Introduction to Chinook

We are a Calgary-based public petroleum and natural gas production company focused on development and exploration opportunities in western Canada. Our operations combine multi-zone conventional production and resource plays in our Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in northwestern Alberta and northeastern British Columbia. We are currently focused on the development of Montney liquids rich natural gas on our Birley/Umbach British Columbia 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, effective January 1, 2014, of all of the issued and outstanding shares of its wholly-owned subsidiary Storm Ventures International (Barbados) Limited (“SVI Barbados”) in consideration for $140.5 million, including $15.8 million of working capital (the “Tunisian Disposition Transaction”) pursuant to a share purchase and sale agreement dated as of June 14, 2014 (the “PSA”). SVI Barbados’ wholly-owned subsidiary was Storm Sahara Limited (“SSL”). Combined, SVI Barbados and SSL held both of Chinook’s Tunisian operating branches previously reported as the Tunisian segment in addition to a portion of the Corporate segment (combined the “Discontinued Tunisian Operations”). This disposition represented our complete exit from Tunisian crude oil and natural gas development and exploration.

The financial and operating results of the Discontinued Tunisian Operations for the periods ended August 19, 2014, the date our control ceased, and the comparative year ended 2013, are separately presented in the “Discontinued Tunisian Operations” section of this MD&A.

Continuing Operations

Our western Canadian petroleum and natural gas producing and exploration assets, previously reported as our Canadian segment, in addition to the remaining portion of our Corporate segment (combined the “Continuing Canadian Operations”) are discussed in the “Continuing Canadian Operations” section of this MD&A. Unless specifically noted, all current and comparative reporting periods’ operating and financial disclosures and discussion are in reference to our Continuing Canadian Operations.

Forward-Looking Information

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

Financial and Operating Highlights

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
CONTINUING CANADIAN OPERATIONS [(1) (2)]				
Production				
Crude oil (bbl/d)	**1,981**	1,840	**2,038**	1,713
Natural gas liquids (boe/d)	**778**	722	**779**	838
Natural gas (mcf/d)	**34,879**	32,287	**30,721**	34,125
Average daily production (boe/d)	**8,572**	7,943	**7,937**	8,238
Sales Prices				
Average oil price ($/bbl)	**$ 70.84**	$ 81.18	**$ 90.68**	$ 88.60
Average natural gas liquids price ($/boe)	**$ 48.05**	$ 63.74	**$ 65.02**	$ 59.72
Average natural gas price ($/mcf)	**$ 3.57**	$ 3.57	**$ 4.59**	$ 3.29
Netback [(3)]				
Average commodity pricing ($/boe)	**$ 35.26**	$ 39.09	**$ 47.44**	$ 38.13
Royalties ($/boe)	**$ (4.74)**	$ (4.80)	**$ (6.48)**	$ (4.39)
Net production expenses ($/boe) [(3)]	**$ (18.89)**	$ (15.83)	**$ (17.61)**	$ (15.69)
G&A expense ($/boe)	**$ (4.26)**	$ (3.47)	**$ (4.83)**	$ (2.75)
Netback ($/boe) [(3)]	**$ 7.37**	$ 14.99	**$ 18.52**	$ 15.30
Wells Drilled (net)				
Oil	**1.62**	1.65	**6.14**	6.02
Gas	**0.83**	-	**2.70**	2.24
Disposal/injection	**-**	-	**0.37**	-
Total wells drilled (net)	**2.45**	1.65	**9.21**	8.26
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 24,065**	$ 25,055	**$ 118,662**	$ 101,433
Funds from operations [(3)]	**$ 6,069**	$ 8,786	**$ 48,158**	$ 41,114
Per share - basic and diluted ($/share)	**$ 0.03**	$ 0.04	**$ 0.22**	$ 0.19
Net loss from continuing operations	**$ (58,311)**	$ (10,151)	**$ (50,672)**	$ (9,453)
Per share - basic and diluted ($/share)	**$ (0.27)**	$ (0.05)	**$ (0.24)**	$ (0.03)
Net loss [(4)]	**$ (60,348)**	$ (39,002)	**$ (38,400)**	$ (26,700)
Per share - basic and diluted ($/share)	**$ (0.28)**	$ (0.18)	**$ (0.18)**	$ (0.12)
Capital expenditures and business combination	**$ 39,671**	$ 9,854	**$ 96,584**	$ 42,586
Net debt (surplus) [(3) (5)]	**$ (28,788)**	$ 61,849	**$ (28,788)**	$ 61,849
Total assets [(5)]	**$ 434,318**	$ 555,341	**$ 434,318**	$ 555,341
Common Shares (thousands)				
Weighted average during period				
- basic & diluted	**215,081**	214,188	**214,601**	214,188
Outstanding at period end	**215,082**	214,188	**215,082**	214,188

(1) Throughout this MD&A our production is presented in either barrels of oil ("bbl"), thousands of cubic feet ("mcf") or barrels of oil equivalent ("boe"); production per day is presented as bbl/d, mcf/d, and boe/d, respectively; commodity prices or revenues and expense per sales are presented as $/bbl, $/mcf, and $/boe, respectively. With respect to our Continuing Canadian Operations, production volumes and sales volumes equal.

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

(3) Funds from operations, funds from operations per share, net debt (surplus), netback and net production expense are non-IFRS measures as defined throughout this MD&A. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

(4) Includes the financial results from the Discontinued Tunisian Operations sold on August 19, 2014.

(5) The comparative periods include the Discontinued Tunisian Operations' assets or working capital excluding marked-to-market derivative contracts, as applicable.

2014 Annual Guidance and Financial Highlights

A summary of our revised 2014 guidance, as announced on December 2, 2014, and a review of our actual results:

($ millions, except boe/d)	2014 Guidance [2]	2014 Actuals
Average production (boe/d)	7,800-8,000	7,937
Exit production (boe/d)	8,250-8,550	8,000
Funds from operations [1]	$ 51-53	$ 48
Capital expenditures and decommissioning expenditures [3]	$ 79	$ 83
Net debt/(surplus) [1]	$ (38)	$ (29)

(1) Funds from operations and net debt (surplus) are non-IFRS measures as defined throughout this MD&A. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.
(2) Guidance as released on December 2, 2014.
(3) Excludes our fourth quarter business combination.

Our production for 2014 was consistent with guidance reflecting the positive results of our 2014 drilling program which focused on opportunities in our core areas in northwestern Alberta and northeastern British Columbia and our strategic acquisition during the fourth quarter of approximately 1,200 boe/d in our Birley/Umbach core area. This operated acquisition included a 100% working interest in an 18 mmcf/d natural gas plant and a 55 kilometre-long 12 inch sales gas pipeline which intersects our Birley/Umbach lands. Despite achieving guidance production, the industry experienced decreased crude oil prices during December 2014 which lowered our funds from operations. Our exit production was generally on guidance, with the exception of sales restrictions that lowered our Karr properties' expected production. We acquired additional lands in the Birley/Umbach area which resulted in us exceeding our capital expenditure guidance. This additional capital expenditure and lower funds from operations, as well as $2.1 million in additional expenses and provisions related to indemnifications we made to the purchaser of the Discontinued Tunisian Operations, resulted in us reporting a lower than guidance net surplus of $29 million. However, when combined with the gross proceeds of $40.9 million we received on January 6, 2015 for our Karr properties we have a pro-forma net surplus of $69.7 million. With this strong financial position, including no long-term debt and our 2014 exit from Tunisia, we are well positioned to exercise our financial optionality and flexibility throughout 2015.

Continuing Canadian Operations

Petroleum and Natural Gas Production Volumes

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Crude Oil (bbl/d)	**1,981**	1,840	**2,038**	1,713
Natural Gas Liquids (boe/d)	**778**	722	**779**	838
Natural Gas (mcf/d)	**34,879**	32,287	**30,721**	34,125
Total (boe/d)	**8,572**	7,943	**7,937**	8,238

Our fourth quarter production volumes increased by 629 boe/d or eight percent compared to the same quarter of 2013. This increase includes production from a natural gas property acquisition in addition to the focused development of liquids rich natural gas properties in northeastern British Columbia and crude oil properties located near Grande Prairie, Alberta.

In the Birley/Umbach area we have drilled three (2.25 net) wells during the reported year with two being completed and on-stream and the third awaiting completion. The first well (0.75 net) came on production during the second quarter of 2014 and averaged 3,500 mcf/d of natural gas and 68 boe/d of natural gas liquids gross production over its first 205 days of production. The second well (0.75 net) was drilled and completed in the third quarter of 2014 and was brought on-stream during the fourth quarter at an average restricted rate of 4,400 mcf/d of natural gas and 48 boe/d natural gas liquids gross production over its first 68 days of production. In November 2014 we also acquired 1,200 boe/d of natural gas properties with key operating and 100% owned infrastructure which we believe strategic to the long term delivery of volumes from the Birley/Umbach area.

During the fourth quarter, our crude oil production volumes increased by 141 bbl/d compared to the same quarter of 2013. This increase resulted from the wells drilled during our previous winter program which were equipped and placed on-stream during the fourth quarter. This drilling program was focused on the development of our crude oil properties located in Albright and a Montney prospect at Gold Creek. Our first horizontal Montney oil well (0.37 net) at Gold Creek averaged 281 bbl/d of crude oil and 3,600 mcf/d of natural gas during its first 82 days of production during the fourth quarter. Our second horizontal Montney well (0.75 net) at Gold Creek saw final test rates of 870 boe/d and we anticipate that this well will be placed on-stream during the third quarter of 2015.

For the current reported year, our overall production volumes decreased compared to the same period of 2013. This decrease resulted from our 2013 and 2014 non-core property dispositions, third party pipeline and plant capacity restrictions in the Grande Prairie area and natural reservoir declines. Our 2014 dispositions included the majority of our assets in our non-core Gilby operating area. At the time of this sale, Gilby sales volumes averaged approximately 800 boe/d.

We also expect to shut-in approximately 500 boe/d of lower netback production in 2015.

Petroleum and Natural Gas Revenues and Realized Pricing

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2014**	2013	**2014**	2013
Oil sales	**$ 12,907**	$ 13,736	**$ 67,448**	$ 55,395
$/bbl	**70.84**	81.18	**90.68**	88.60
Natural gas liquids sales	**$ 3,439**	$ 4,235	**$ 18,496**	$ 18,261
$/boe	**48.05**	63.74	**65.02**	59.72
Natural gas sales	**$ 11,456**	$ 10,591	**$ 51,501**	$ 40,991
$/mcf	**3.57**	3.57	**4.59**	3.29
Petroleum and natural gas revenue	**$ 27,802**	$ 28,562	**$ 137,445**	$ 114,647
$/boe	**35.26**	39.09	**47.44**	38.13

Our petroleum and natural gas revenues of $137.4 million during the reported year increased compared to the same period of 2013. This increase was caused by both higher realized commodity pricing and an increase in crude oil sales volumes. The increase in crude oil sales volumes was the result of our focused development of crude oil properties located near Grande Prairie, Alberta. This development, in conjunction with our 2013 disposition of predominately dry natural gas properties, increased our ratio of the relatively higher priced crude oil sales to 26% of total sales volumes during the reported year compared to 21% in the same period of 2013. This increased ratio of crude oil to total sales volumes contributed to our higher realized commodity pricing per boe.

During the fourth quarter our petroleum and natural gas revenues of $27.8 million decreased compared to the same quarter of 2013. Despite increased sales including higher crude oil volumes, this decrease in revenues was the result of lower realized petroleum pricing. We realized higher commodity prices for the first three quarters of 2014 but experienced lower petroleum pricing during the fourth quarter. Despite this decrease, liquids pricing continued to retain its price premium relative to the price received for an equivalent heating unit of natural gas.

As already mentioned, partially offsetting the decrease in the realized price for the fourth quarter was higher sales volumes which included our focused development of liquids rich natural gas properties and a natural gas acquisition in northeastern British Columbia. Although we increased crude oil sales volumes from our development in the Grande Prairie area, the increase in natural gas sales volumes resulted in an equivalent ratio of crude oil sales to total sales volumes of 23% for both the fourth quarters of 2014 and 2013. This equivalent ratio resulted in us reporting the effect of lower benchmark petroleum pricing in our weighted average realized price.

Benchmark Prices

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Crude Oil				
Canadian light sweet [1] ($/bbl)	**$ 74.37**	$ 86.32	**$ 93.99**	$ 92.96
Natural gas liquids				
WTI [2] ($US/bbl)	**$ 73.15**	$ 97.46	**$ 93.00**	$ 97.97
Natural gas				
AECO Gas [3] ($/mcf)	**$ 3.65**	$ 3.59	**$ 4.57**	$ 3.22

(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 fourth quarter but increased during the full year, as did our average realized crude oil prices, compared to the same periods of 2013. Our quality remained relatively consistent for the current reporting periods as compared to the same periods in 2013.

Natural Gas Liquids Pricing

Our natural gas liquids price is a blend of prices received for a range of liquids from ethane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however we benchmark our liquids in reference to Canadian light sweet or WTI. During the fourth quarter, our realized natural gas liquids price and our price relative to Canadian light sweet oil of $48.05/bbl and 66%, respectively, decreased compared to $63.74/bbl and 74% for the same quarter of 2013. These decreases were the result of lower average benchmark pricing for these liquid commodities compared to the decrease in the Canadian light sweet benchmark, especially as related to propane and pentane. For the reported year, our realized natural gas liquids price and our price relative to Canadian light sweet increased to $65.02/bbl and 70%, respectively, compared to $59.72/bbl and 64% for the same period of 2013. These increases were due to a higher ratio of our mix being contributed from condensates with its associated higher realized price. This higher condensate ratio resulted from the production from our new Birley/Umbach wells.

Natural Gas Pricing

We realized natural gas prices of $3.57/mcf for both fourth quarters of 2014 and 2013. Our realized natural gas price of $4.59/mcf for the reported year showed significant improvement from $3.29/mcf reported for the same period of 2013. Although an equivalent boe of natural gas continues to sell at a significant discount relative to a barrel of oil, we realized a 40% increase in our natural gas prices during the reported year compared to the same period of 2013 which was a result of the higher AECO benchmark prices. Although AECO benchmark pricing has fallen since the first quarter, this benchmark's pricing in the reported year remained higher than in the comparative period.

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2014**	2013	**2014**	2013
Royalties	**$ 3,737**	$ 3,507	**$ 18,783**	$ 13,214
Per sales ($/boe)	**$ 4.74**	$ 4.80	**$ 6.48**	$ 4.39
Percent of Revenues (%)	**13**	12	**14**	12

For the current reporting periods our royalties increased on an overall basis and as a percentage of revenue, compared to the same periods of 2013. These increases included the effects of recent new crude oil wells sales volumes in the Elmworth area coming off an initial royalty incentive program and increases in crude oil sales volumes with its relatively higher associated royalty rate. The increase in the realized sales price during the current reported year resulted in higher royalties per boe compared to the same period of 2013. For the fourth quarter we observed the opposite effect as the decrease in the royalties per boe resulted from a lower realized price as compared to the same quarter of 2013. Adjustments to our gas cost allowance during the current reporting year also affected our royalties overall, on a boe basis and as a percentage of revenue.

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 flow. This provides more certainty within determined commodities price ranges as to what we will receive on a portion of our crude oil and/or natural gas sales volumes. While 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 and/or collar commodity price derivative contracts are reported at their approximated fair value on the date of the Financial Statements. These estimated fair values are partially determined through the difference in the referenced market forward prices of the respective commodities over the remaining periods of the contracts as compared to our received prices multiplied by the remaining notional volumes. Volatility in commodity prices and any decreases in the remaining notional volumes will result in changes in the fair value of our derivative contracts from one period to the next. These changes in the fair value between reporting periods are recognized in net loss as unrealized gains or losses on derivative contracts. Realized gains or losses on derivative contracts are recognized in net loss on the unwinding of the financial derivative contract term. For the current reporting periods and their comparative periods of 2013, we reported the following realized and unrealized gains and losses on our derivative contracts:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Realized (gains) losses on derivative contracts	**$ (668)**	$ 71	**$ 2,933**	$ (734)
Unrealized (gains) losses on derivative contracts	**(2,065)**	1,394	**(2,428)**	947
Total	**$ (2,733)**	$ 1,465	**$ 505**	$ 213

During the fourth quarter we realized a gain on our WTI derivative contract as this benchmark was lower than our received fixed price contract. During the reported year, we realized a loss on this WTI derivative contract. Including these settlements, our adjusted sales prices for crude oil would have been $75.55/bbl and $90.42/bbl for the current reporting periods compared to our reported prices of $70.84/bbl and $90.68/bbl.

During the current reporting periods, we realized losses on our AECO derivative contracts as the monthly average benchmark prices were higher than our received fixed price contracts. If we had included these settlements in our natural gas revenues, we would have reported adjusted sales prices for the current reporting periods of $3.51/mcf and $4.35/mcf compared to our reported prices of $3.57/mcf and $4.59/mcf.

Our unrealized gains for the current reporting periods includes the decrease in the forward AECO price relative to our received fixed contracted price. As at December 31, 2014, this commodity price contract had an estimated fair value current asset of $1.5 million with the following terms:

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

Based on our revised guidance, this price risk contract is expected to secure our received commodity prices on approximately 13% of natural gas sales volumes during the year ended 2015.

Production and Operating Expense

($ thousands, except where noted)	Three months ended December 31 2014	2013	Year ended December 31 2014	2013
Production & operating	**$ 15,742**	$ 12,735	**$ 56,324**	$ 54,382
Less:				
Processing & gathering revenues	**(848)**	(1,168)	**(5,308)**	(7,205)
Net production & operating expense [(1)]	**$ 14,894**	$ 11,567	**$ 51,016**	$ 47,177
Per sales net production & operating expenses ($/boe) [(1)]	**$ 18.89**	$ 15.83	**$ 17.61**	$ 15.69
Per sales production & operating expenses ($/boe)	**$ 19.96**	$ 17.43	**$ 19.44**	$ 18.09

(1) Net production and operating expense and net production and operating expense per boe are non-IFRS measures and are calculated as production and operating expense less processing and gathering revenues. Management uses the net production and operating expense non-IFRS measure to determine the current periods' cash cost of operating expenses and the net production and operating expense per boe is used to measure operating efficiency on a comparative basis. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

Our production and operating expense of $15.7 million and $56.3 million for the current reporting periods increased compared to the same periods of 2013. These increases partially resulted from higher crude oil production volumes as our crude oil is generally produced at a higher operating cost per barrel than an energy equivalent volume of natural gas. More oil, water and emulsion hauling, emulsion processing and water disposal coupled with rapidly increasing demand for these services in our core operating areas contributed to these increases. For the current reporting periods, these operating costs on a boe basis were also affected by start-up costs at our Montney prospect located at Gold Creek and third party pipeline and facility capacity constraints in the Grande Prairie area. These capacity constraints lowered our sales volumes but without a corresponding decrease in our operating costs.

During the fourth quarter, at our Birley/Umbach area we also added liquids rich natural gas sales volumes from recent drilling success in addition to natural gas volumes from an acquisition. Our recent drilling success in this area is in the start-up phase. These added sales volumes also increased our current reporting periods' operating costs overall and on a boe basis, compared to the same periods of 2013. However, the recent reduction in commodity pricing has delayed our original plans to accelerate development of this area. We expect decreases in both our operating costs overall and on boe basis as sales volumes from future developments at Birley/Umbach are brought on-stream and we gain cost synergies from our recent acquisition given our existing operations in this area.

We also incurred charges during the current reporting periods for turnarounds, workovers, compressors and culvert and pipeline repairs totalling $1.5 million and $2.8 million. These costs also had the effect of increasing our production and operating costs in total and on a boe basis.

With recent commodity pricing we are confronted by an operating cost structure that simply is too high. We are targeting significant cost reductions as demonstrated through our updated 2015 guidance which forecasts production and operating costs of between $41 million and $43 million. We expect to partially achieve these improvements through shutting in 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 comprising our commitment to health and safety.

Processing and gathering revenue decreased during the current reporting periods compared to the same periods of 2013. The sale of the Gilby area assets during the fourth quarter included certain processing facilities and distribution pipelines. This resulted in lower processing and gathering revenues. In addition, during the year ended 2013, we reported higher throughput of third party volumes through our processing facilities and distribution pipelines.

General & Administrative ("G&A") Expense

($ thousands, except where noted)	Three months ended December 31 2014	2013	Year ended December 31 2014	2013
G&A expense	**$ 3,356**	$ 2,536	**$ 13,980**	$ 8,243
Per sales ($/boe)	**$ 4.26**	$ 3.47	**$ 4.83**	$ 2.75

G&A expense for the current reporting periods increased compared to the same periods of 2013. This is mostly due to lower reported overhead recoveries including those from our joint venture partners. For the reported year, a related party recovery of $1.3 million decreased compared to $4.0 million for the same period of 2013. During 2015, we expect this related party recovery to increase. In addition, the increase in the weighted average working interests of our current operated activities lowered our overhead recoveries from these partners. For the current reporting periods, in comparison to the same periods in 2013, we also reported increases in both staff salaries and consulting fees. In addition, for the reported year we incurred $1.1 million of staff incentive compensation. We also had previously dedicated a portion of our office to support the Discontinued Tunisian Operations but since we continued to incur such costs after its sale, during the current reporting periods we are reporting these costs through our Continuing Canadian Operations G&A expense. These changes increased our G&A expense for the current reporting periods in total and on a per boe basis compared to the same periods of 2013. When combined with lower sales volumes for the reported year, the effect was a further increase in the reported G&A expense on a boe basis.

With the announced decreased expenditures for our 2015 capital program, we are currently evaluating our G&A cost structure which, like our operating cost structure, is simply too high. This evaluation has already resulted in costs savings as we have reduced our dependency on consultants and software licensing. We are currently evaluating our existing staffing levels in addition to all facets of our office cost structure. As included in our revised 2015 guidance, our G&A costs for 2015 are expected to materially decrease from our 2014 levels.

Netback

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

	Three months ended December 31		Year ended December 31	
Per sales ($/boe)	**2014**	2013	**2014**	2013
Realized sales price	**$ 35.26**	$ 39.09	**$ 47.44**	$ 38.13
Less:				
Royalties	**(4.74)**	(4.80)	**(6.48)**	(4.39)
Net production expense [(2)]	**(18.89)**	(15.83)	**(17.61)**	(15.69)
G&A expense	**(4.26)**	(3.47)	**(4.83)**	(2.75)
Netback [(1)]	**$ 7.37**	$ 14.99	**$ 18.52**	$ 15.30

(1) Netback is a non-IFRS measure and is calculated as a period's sales of petroleum and natural gas, net of royalties less net production and operating expenses and G&A expense, divided by the period's sales volumes. We use this non-IFRS measure to assist us in understanding our profitability relative to current commodity prices and it provides an analytical tool to benchmark changes in operational performance against prior periods.
(2) See the production and operating expense table where this non-IFRS measure is defined.

Our netback for the reported year increased 21% compared to the same period of 2013. Contributing to this increase were higher benchmarked prices whose effect was magnified through a higher proportion of crude oil sales volumes relative to total sales volumes. We achieve a higher realized sales price per barrel on our crude oil sales than we do on an equivalent boe of natural gas. The increase in the proportion of our crude oil resulted from our focussed development of our Albright and Montney prospect at Gold Creek combined with dispositions of dry natural gas properties throughout 2013.

Our netback for the fourth quarter decreased compared to the same quarter of 2013. This decrease was a result of lower petroleum pricing and higher net production and G&A expenses. Decreases in market benchmark liquids pricing, especially during December 2014, combined with the effect of higher associated natural gas production from our Birley/Umbach area development and acquisition resulted in a lower realized sales price. This increase in natural gas production lowered our ratio of crude oil sales to total sales volumes. This lower ratio resulted in us reporting the full effect of the fourth quarter's decrease in benchmarked liquids' pricing. Start-up costs at our core area properties, third party capacity constraints and costs that are one-time in nature combined to increase our net production expense per boe. A shift to higher working interest operated properties that lowered our recoveries, increases in our staffing and consulting costs and legacy costs previously incurred to support the Discontinued Tunisian Operations combined to increase our G&A expense on a boe basis.

Exploration and Evaluation Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Exploration and evaluation expenditures	**$ 569**	$ 1,320	**$ 1,632**	$ 3,951

Our exploration and evaluation expense decreased during the current reporting periods compared the same periods of 2013. For the current and comparative reporting periods, this expense was due to pre-licensing evaluation, exploratory lease rental and geological and geophysical costs.

During the fourth quarter of 2013, we evaluated the recoverability of an exploration well's costs prior to transferring these costs to D&P Assets on the basis of establishing commercial reserves. At the time of transfer, we determined that the drilling and completion costs of the well were impaired by $0.8 million relative to the associated proved plus probable discounted reserves. These costs were charged directly to exploration and evaluation expense. Finally, during the year ended December 31, 2013, we also completed our evaluation and determined that an exploration well drilled during 2012, at a cost of $1.4 million, was unsuccessful for petroleum or natural gas reserves. These costs were transferred from E&E Assets to exploration and evaluation expense.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2014**	2013	**2014**	2013
Depletion, depreciation and amortization	**$ 12,677**	$ 10,902	**$ 48,813**	$ 50,199
Per sales ($/boe)	**$ 16.08**	$ 14.92	**$ 16.85**	$ 16.69

DD&A expense on an overall dollar basis increased during the fourth quarter whereas it decreased during the reported year when compared to the same periods of 2013. These changes are consistent with the same periods' changes of sales volumes. On a boe basis, the increase in DD&A expense in the current reporting periods, compared to the same periods in 2013, resulted from higher amortization associated with the 25 additional sections of 100% working interest land in the Birley/Umbach area that we acquired at the May and November Crown land sales.

Impairment of Development & Production Assets

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2014**	2013	**2014**	2013
Impairment of development & production assets	**$ 63,500**	$ 3,500	**$ 63,500**	$ 3,500

We group our development and production ("D&P") assets into cash generating units ("CGUs") for the purpose of assessing impairment or recovery of prior periods' reported impairments. We perform impairment tests whenever events and circumstances arise during the development and production phase indicate that the carrying value of a CGU may exceed its recoverable amount.

During the fourth quarter, we reviewed and adjusted the number of CGUs as a result of changes observed during the current reporting year's commodity mix which was achieved through the combination of core area development and the disposition of non-core properties. We are focused on the development of our Peace River Arch Montney based CGU which includes the Birley/Umbach area located in northeastern British Columbia and our Grand Prairie CGU which includes the Albright and Gold Creek areas located in northwestern Alberta. We anticipate funding future development of these areas through the proceeds received on August 19, 2014 from the sale of the Discontinued Tunisian Operations in addition to proceeds from other non-core property dispositions. The majority of property dispositions over the last year, including the Gilby disposition that closed December 18, 2014, were located in our other two CGUs of central and eastern Alberta. As a result, effective October 1, 2014, we combined the two central and eastern Alberta CGUs into one. We now have three CGUs.

We identified triggers indicating impairment of our CGUs. These triggers resulted from changes in recoverable value from the continued disposition of producing assets and the reduction in forward Canadian petroleum and natural gas prices. We reported impairment in all of our CGUs for the year ended December 31, 2012 and in one of our CGUs for $3.5 million for the year ended December 31, 2013. Upon reporting these previous impairment expenses, each CGU's carrying value approximated its recoverable value. As at December 31, 2014, our testing of each of our CGU's recoverable value relative to its carrying values revealed an impairment charge totaling $63.5 million with impairment being recorded in each of our three CGUs. Had we continued to have four CGUs, the impairment charge would not have changed relative to that being reported. Each CGU's recoverable value was estimated using a value in use calculation based on expected future cash flows anticipated to be produced from proved plus probable reserves, using a discount rate ranging between 10% to 15%, depending on the category of reserves, and forward commodity price estimates.

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 $28.0 million and $7.0 million, respectively. The impairment tests as carried out at December 31, 2014 and 2013 were based on the following forward price estimates:

	Edmonton Light Crude Oil ($/bbl) [1]		AECO Gas ($/mmbtu) [1]	
As at December 31	**2014**	**2013**	**2014**	**2013**
2015	$ 68.60	$ 96.50	$ 3.50	$ 4.25
2016	$ 83.20	$ 97.50	$ 4.00	$ 4.55
2017	$ 88.90	$ 98.00	$ 4.25	$ 4.75
2018	$ 94.60	$ 98.30	$ 4.50	$ 5.00
2019	$ 99.60	$ 99.60	$ 4.70	$ 5.25
Thereafter	2%/yr	2%/yr	2%/yr	2%/yr

(1) Source: McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2014 and 2015.

Gains on Disposition of Properties

During the reported year, we completed the sale of several petroleum and natural gas properties located throughout Alberta for aggregate proceeds of $35.6 million (same period of 2013 - $21.0 million). These dispositions included the sale of the Gilby area which was sold on December 18, 2014 for net proceeds of $28.1 million. The combined carrying amounts of these properties, net of the disposed decommissioning obligations, was less than the received sale proceeds resulting in a gain of $11.4 million for the reported year.

We also reported a gain of $3.7 million from undeveloped lands as exchanged as partial consideration for a strategic acquisition in the Birley/Umbach area. The total reported gains from property dispositions for the reported year is $15.1 million as compared to $12.9 million for the same period in 2013.

Effective October 1, 2014, we entered into an agreement to sell certain of our petroleum and natural gas properties and undeveloped lands located in the Karr area of northwestern Alberta for gross proceeds of $40.9 million. These proceeds relative to the net carrying amount of $23.7 million for these properties less decommissioning obligations of $0.8 million is expected to result in a gain on disposition of these properties of approximately $18.0 million to be reported during the first quarter of 2015. The increase in the fair value of these properties relative to incurred costs resulted from the discovery of crude oil reserves. These properties' carrying amounts and recoverable values from before tax cash flows from total proved and total proved and probable reserves discounted at 10% of $16.7 million and $25.1 million, respectively, were not included in our December 31, 2014 assessment of impairment as previously discussed. This transaction closed on January 6, 2015.

Share-Based Compensation

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2014**	2013	**2014**	2013
Share-based compensation	**$ 377**	$ 234	**$ 938**	$ 1,329
Per sales ($/boe)	**$ 0.48**	$ 0.32	**$ 0.32**	$ 0.44

For the fourth quarter, share-based compensation increased as a result of the expensing of restricted and performance awards which were granted for the first time during 2014 and share options granted. During the reported year, share-based compensation decreased as the increase in this expense from the grant of restricted awards and performance awards was more than offset by a decrease resulting from a lower remaining unamortized fair value for unvested outstanding share options.

Bad Debt Expense

In an effort to manage our credit risk we continuously monitor and assess the collectability of our joint venture partners' receivables in addition to our other receivable positions. During the reported year, as it related to our joint venture partners, we provided for $1.2 million of receivables that were deemed uncollectible compared to $1.8 million during the same period of 2013.

Foreign Exchange & Other Losses (Gains)

	Three months ended December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Foreign exchange and other losses (gains)	**$ 87**	$ 1,146	**$ (2,293)**	$ 1,228

During the reported year we recognized foreign exchange gains from holding US dollar denominated Tunisian Disposition Transaction proceeds prior to conversion or reporting in Canadian dollars. We were holding only a nominal amount of these US dollars at December 31, 2014 in an international subsidiary as substantially all of the Tunisian Disposition Transaction proceeds had been repatriated to Canada and converted into Canadian dollars. We continue to hold US$4.8 million as a hedge to expected US dollar costs associated to this transaction and indemnifications provided to the buyer of the Tunisian Discontinued Operations.

Financing Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Interest and financing charges	**$ 131**	$ 928	**$ 2,634**	$ 4,382
Amortization of deferred financing costs	**-**	75	**343**	270
Accretion of decommissioning obligation	**681**	621	**2,712**	2,586
Total	**$ 812**	$ 1,624	**$ 5,689**	$ 7,238

The decreases in our interest and financing charges for the current reporting periods, compared to the same periods of 2013, resulted from our repayment of the outstanding debt balance during the third quarter of 2014, as financed from the Tunisian Disposition Transaction proceeds (see "Credit Facility" section of this MD&A). In addition, we incurred lower interest and financing charges as a result of lower average effective interest rates. Our average effective interest rates during the reported year of 4.1% decreased from 5.0% in the same period of 2013. This decrease is consistent with lower bankers' acceptance and prime rates. The nominal interest charged in the fourth quarter relates to stand-by fees on the full availability of our credit facility. The amortization of deferred financing costs increased during the reported year as we expensed the remaining outstanding balance during the third quarter of 2014 in conjunction with the repayment of the entire balance of the Revolving Term Credit Facility.

Income Tax

We have not reported deferred tax assets because it is not probable that we can utilize these assets against future taxable profit. At December 31, 2014, we had the following tax pools:

($ thousands)	**December 31 2014**
Canadian oil and gas property expense	**$ 61,939**
Canadian development expense	**85,115**
Canadian exploration expense	**56,015**
Undepreciated captial costs	**49,761**
Non-capital losses	**183,254**
Other	**3,662**
Total	**$ 439,746**

Based on our expected cash flow and available tax pools, we do not expect to incur corporate taxes in the near term.

Discontinued Tunisian Operations

The operating results for the Discontinued Tunisian Operations are shown in the following table for the noted periods:

	Year ended December 31	
DISCONTINUED OPERATIONS	**2014 (1)**	2013
($ thousands)		
Crude oil & natural gas revenues	**$ 36,911**	$ 74,605
Royalties & expenses	**(30,335)**	(86,233)
Income (loss) from discontinued operations	**6,576**	(11,628)
Gain on sale of discontinued operations	**1,037**	-
Realized accumulated other comprehensive income on the disposition of foreign operations	**9,546**	-
Income tax expense	**(4,887)**	(5,619)
Net income (loss) from discontinued operations	**$ 12,272**	$ (17,247)

(1) During the reported year, the Discontinued Tunisian Operations period ended on August 19, 2014, the date that the Tunisian Disposition Transaction closed.

During the reported year, income before income taxes from discontinued operations increased compared to the loss reported for the same period in 2013. This increase was due to lower royalties and expenses, as partially offset by lower crude oil and natural gas revenues. These lower revenues resulted from lower sales volumes due to the shorter current reporting period which ended on August 19, 2014. In addition, this shorter reporting period did not allow us to accumulate sufficient crude oil from our third quarter of 2014 production volumes to make a delivery to a tanker. As a result we stored the crude oil production and reported the associated costs (royalties, operating and DD&A) as the carrying value of crude oil inventory in addition to a lower income tax expense.

The comparative period's expense was also higher because of a $32.0 million impairment charge. This charge was reported against one of the Discontinued Tunisian Operations' CGUs as triggered by our decision to further evaluate the development options for this CGU and the change in classification of this CGU's proved plus probable reserves to a contingent resource. We assessed this CGU's recoverable value based on a fair value less costs to sell as determined from third party market transactions for similar contingent resource development projects.

During the fourth quarter, we were made aware of and correspondingly increased expenses by $2.1 million for additional expenses and upon assessing a probable outflow of resources related to the indemnifications we made to the purchaser pursuant to the PSA.

On August 19, 2014, the inventory carrying value, along with the other net assets of this discontinued operation, were less than the disposition proceeds, net of transaction costs. This resulted in a gain on the sale of discounted operations of $1.0 million.

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

Net and Comprehensive Losses

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2014**	2013	**2014**	2013
Weighted average shares outstanding - basic & diluted (thousands)	**215,081**	214,188	**214,601**	214,188
Net loss from continuing operations	**$ (58,311)**	$ (10,151)	**$ (50,672)**	$ (9,453)
Per share - basic & diluted ($/share)	**$ (0.27)**	$ (0.05)	**$ (0.24)**	$ (0.03)
Net loss	**$ (60,348)**	$ (39,002)	**$ (38,400)**	$ (26,700)
Per share - basic & diluted ($/share)	**$ (0.28)**	$ (0.18)	**$ (0.18)**	$ (0.12)
Comprehensive loss	**$ (60,349)**	$ (34,172)	**$ (44,641)**	$ (18,174)
Per share - basic and diluted ($/share)	**$ (0.28)**	$ (0.16)	**$ (0.21)**	$ (0.08)

Our net losses from continuing operations of $58.3 million and $50.7 million in the current reporting periods increased relative to the same periods of 2013. These increases resulted from higher impairment charges of $63.5 million during the current reporting periods compared to $3.5 million during the same periods of 2013. The increases in our continuing operations' net losses were also caused by higher expenses which included operating and G&A charges. Further contributing to our fourth quarter continuing operations' net loss was a decrease in realized commodity pricing. Finally, the increase in the reported year's net loss was also caused by lower sales volumes and realized losses from derivative contracts.

The net losses for the current and comparative reporting periods includes the results from both our continuing and discontinued operations (see "Discontinued Tunisian Operations"). The net income from discontinued operations for the reported year was $12.3 million and included the financial results of the Discontinued Tunisian Operations for the 231 days ended August 19, 2014, the date control ceased. Despite a smaller time frame, the net income from discontinued operations increased in comparison to the net loss of $17.3 million reported during the same period of 2013. This increase was assisted by two measures resulting from the sale of the Discontinued Tunisian Operations: a $1.0 million gain on sale and the realization of $9.5 million of foreign exchange gains as accumulated from the net assets of these operations but as offset in other comprehensive income. We also recognized an impairment charge of $32.0 million on the Discontinued Tunisian Operations as reported during 2013.

Given our sale of the Discontinued Tunisian Operations, for the fourth quarter and future reporting periods we will no longer be reporting foreign exchange gains/losses on foreign operations. However, for our other reported periods as defined in this MD&A, the comprehensive losses include our net losses and foreign currency translation gains of the US dollar denominated Discontinued Tunisian Operations. Up to the sale of the Discontinued Tunisian Operations on August 19, 2014, we recognized foreign exchange gains as the carrying value of the Discontinued Tunisian Operations on translation from its functional US dollar increased as reported in Canadian dollars. On disposition of these operations, and as mentioned, for the reported year we moved the $9.5 million of accumulated other comprehensive income to net income from discontinued operations. This move had a nil effect on this year's comprehensive loss.

Capital Resources, Capital Expenditures and Liquidity

We will continue to delineate our large Montney resource at a pace that does not impair its value or growth potential. We believe that preserving our capital flexibility and balance sheet strength to maintain optionality though a low commodity price cycle will be of the greatest benefit to our shareholders. As a result, on January 19, 2015, we announced our reduced 2015 capital program of $44.5 million focussed on further delineating our Montney resource at Birley/Umbach, British Columbia and Gold Creek, Alberta. We are deferring facility installations, and portions of both the pipeline construction and our drilling program, as we will not compromise our most economic rates of return by bringing new wells on production in the current weak commodity price environment. We plan to closely monitor our reduced 2015 capital program and will adjust it accordingly in response to changing commodity prices and to take advantage of strategic growth opportunities that may present themselves as a result of the current industry environment. We intend to finance our 2015 capital program through our December 31, 2014 existing net surplus position including approximately $86.9 million of cash on hand after adjusting for the January 6, 2015 sale of our Karr properties for gross proceeds of $40.9 million.

For the reported year, we financed the repayment of all outstanding debt and our investment in capital, decommissioning, exploration and evaluation expenditures (including our sizeable Montney resource land acquisition) from cash on deposit, funds from operations, non-cash working capital and proceeds from the sale of both non-core properties and the Discontinued Tunisian Operations.

Net Consideration from Sale of Discontinued Tunisian Operations and Other Associated Expenditures, Commitments and Guarantees

Net Consideration

Chinook's wholly-owned subsidiary, SVI (BVI), received the following consideration from the sale of the Discontinued Tunisian Operations:

($ thousands)	August 19 2014
Consideration on sale of discontinued operations	$ 140,480
Cash transaction costs	(7,645)
Net consideration	$ 132,835

During the reported year, all consideration from the sale of the Discontinued Tunisian Operations was received from the purchaser. Our investment in SVI (BVI) had sufficient surplus tax pools which allowed us to repatriate substantially all of the cash proceeds from the British Virgin Islands to Canada net of certain transactions costs without incurring any adverse Canadian cash taxes.

Transaction Costs

Transaction costs, as included against the net income from discontinued operations, include both cash and non-cash expenses. Cash transaction costs of $7.6 million include a success fee to our advisor and expenses for legal fees and severance of our former Canadian-based staff dedicated to the Discontinued Tunisian Operations. Included in this severance expense is $1.6 million for our former officers dedicated to the Discontinued Tunisian Operations as paid in December 2014.

Transaction costs also include another $2.3 million of non-cash costs, which included the following:

- As a condition precedent to the closing of the Tunisian Disposition Transaction, we cancelled our US$75.0 million international amortizing reserve-based credit facility. On cancellation of this facility, we accelerated the amortization of the associated deferred financing costs. As the cancellation of this facility was a condition precedent of the Tunisian Disposition Transaction, we expensed $2.1 million of deferred financing costs as non-cash transaction costs. We had not drawn on this facility at the time it was cancelled.
- As a result of the surrendering and acceleration of vesting dates of certain options held by optionees dedicated to the Discontinued Tunisian Operations (see below for "Other Expenditures & Option Vesting Acceleration"), the associated unamortized fair value of these options was reported as a non-cash transaction cost of $0.2 million.

Other Expenditures & Option Vesting Acceleration

During the reported year, and as a result of the sale of the Discontinued Tunisian Operations, we paid $0.9 million to certain Tunisian-based optionees in consideration for them voluntarily surrendering 1,383,750 of "in-the-money" options. This cash payment represented the fair value of "in-the-money" options at the time of their surrender. It was reported as an increase in the line item of contributed surplus as included on the Balance Sheet. We also accelerated the vesting date of 311,668 options to August 19, 2014, the date the Tunisian Disposition Transaction closed. These options were then exercised by the remaining Tunisian-based optionees at a weighted average exercise price of $1.14 per option. None of these Tunisian-based optionees were officers.

Certain Canadian-based optionees who were previously dedicated to the Discontinued Tunisian Operations, including our former international officers, had their unvested options vest on November 30, 2014. At that time, and consistent with our option plan, these Canadian-based optionees had 60 days to exercise any of their "in-the-money" options. At December 31, 2014, there were 325,837 vested options that had their vesting dates accelerated held by these Canadian-based optionees with a weighted average exercise price of $1.32 per option, of which 193,335 options were held by our former international officers with a weighted average exercise price of $1.34 per option. Other than 16,667 options at a weighted average exercise price of $1.19 per option, the options held by Canadian-based optionees as previously dedicated to the Discontinued Tunisian Operations have now been cancelled.

Guarantees of Indemnities Pursuant to the PSA

SVI (BVI) provided the purchaser with indemnities pursuant to the PSA which indemnities we have guaranteed in accordance with the PSA.

Funds from Operations

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

	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	**2014**	2013	**2014**	2013
Cash flow from continuing operating activities	**$ 8,202**	$ 12,024	**$ 46,257**	$ 27,222
Add back (deduct):				
Change in operating non-cash working capital	**(3,065)**	(3,863)	**(791)**	11,167
Decommissioning obligation expenditures	**932**	625	**2,692**	2,725
Funds from operations (1)	**$ 6,069**	$ 8,786	**$ 48,158**	$ 41,114
Per share - basic and diluted (1)	**$ 0.03**	$ 0.04	**$ 0.22**	$ 0.19
Per sales ($/boe) (1)	**$ 7.70**	$ 12.02	**$ 16.62**	$ 13.67

(1) Funds from operations, funds from operations per share and funds from operations per boe are non-IFRS measures. Funds from operations is calculated from cash flow from continuing operations adjusted for changes in non-cash working capital related to continuing operations and decommissioning obligation expenditures related to continuing operations. Funds from operations per share or per boe is calculated from funds from operations as previously defined divided by the weighted average basic and dilutive shares outstanding during the period or sales volumes, respectively. Funds flow from operations does not include the results of the Discontinued Tunisian Operations. Management believes that funds from operations is a key measure to assess our ability to finance capital expenditures and debt repayments. Funds from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS and should not be construed as an alternative to cash flow from operations.

During the reported year, our funds from operations increased by 17% to $48.2 million compared to the same period of 2013. This increase was due to higher crude oil sales volumes and its higher associated netback, compared to the netback of an equivalent boe of natural gas, and lower cash financing costs. Stronger realized commodity pricing during the reported year, compared to the same period of 2013, also contributed to both a higher netback and our reported increase in funds from operations.

Funds from operations for the fourth quarter decreased from the same quarter of 2013 despite increases in both commodity sales volumes and realized derivative contract gains and lower financing costs. This decrease in funds from operations was due to a lower netback. The lower netback resulted from lower realized petroleum sales prices and increases in both our net production and G&A expenses.

Credit Facility

($ thousands)	**December 31 2014**	December 31 2013 (2)
Long-term debt	**$ -**	$ 75,897
Less:		
Working capital excluding mark-to-market derivative contracts (1)	**(28,788)**	(14,048)
Net debt (surplus) (1)	**$ (28,788)**	$ 61,849

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

(2) Includes balances related to the Discontinued Tunisian Operations which was sold during the third quarter of 2014.

We had a net surplus of $28.8 million at December 31, 2014, compared to net debt of $61.8 million at December 31, 2013. This positive change of $90.6 million from net debt to surplus is primarily due to the proceeds of $140.5 million received from the sale of the Discontinued Tunisian Operations, proceeds of $35.6 million from Canadian non-core property dispositions, funds from operations of $48.2 million and $2.6 million of foreign exchange gains on cash, less capital, a business acquisition, decommissioning, exploration and evaluation expenditures totalling $100.9 million and less the effect of the Discontinued Tunisian Operations. This effect includes relinquished working capital, cash-based transaction costs and the amortization of deferred financing costs for a total of $34.6 million.

During the third quarter of 2014 we repaid our Canadian credit facility and amortized its remaining $0.2 million of deferred financing costs. As at December 31, 2014, we had no outstanding borrowings compared to the $78.5 million in borrowings as at December 31, 2013.

On June 25, 2014, we extended the current revolving period of our Canadian reserve-based 364 day revolving credit facility (the "Revolving Term Credit Facility"), which we hold with a syndicate of Canadian banks, to June 25, 2015 and the maximum availability of the facility was increased to $125.0 million (December 31, 2013 - $115.0 million). On or before June 25, 2015, the facility's revolving period and availability will be reassessed and in the event that the revolving period is not extended further by the banking syndicate, all amounts then outstanding under the facility must be repaid before June 24, 2016. The Revolving Term Credit Facility is subject to a semi-annual review and redetermination. Changes in the availability of the Revolving Term Credit Facility are possible, from one renewal period to the next, with draws in excess of availability becoming payable within 60 days. At December 31, 2014, we had no drawings under this facility but had outstanding letters of credit totalling $0.3 million. This resulted in available credit on this facility of $124.7 million (December 31, 2013 – drawings of $78.5 million, outstanding letters of credit of $0.4 million and $36.1 million in available credit).

The Revolving Term Credit Facility is guaranteed by our Canadian subsidiaries and collateralized by floating charges and security interests over all present and future Canadian properties and other Canadian assets and our Canadian subsidiaries. Our selection of interest rate options include rates for either the Canadian prime, US Base, Bankers' Acceptances or US LIBOR. The Revolving Term Credit Facility contains a covenant whereby the ratio of our debt or borrowed money which included drawings against this facility, to our earnings attributable to the Canadian operations before interest, taxes, depreciation/depletion and amortization cannot be greater than 4:1 as determined on a rolling four quarter basis for the most current fiscal quarter. At December 31, 2014, we were in compliance with this covenant and anticipate being in compliance through the existing term of this facility.

Capital Expenditures

Capital expenditures were as follows:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Land and lease	**$ 4,054**	$ -	**$ 18,388**	$ 3,255
Drilling and completions	**14,319**	5,944	**44,601**	27,398
Facilities and equipment	**5,128**	3,638	**16,200**	10,798
Field expenditures	**23,501**	9,582	**79,189**	41,451
Capitalized G&A	**259**	272	**1,110**	1,101
Furniture and equipment	**61**	-	**435**	34
Acquisitions	**15,850**	-	**15,850**	-
Total	**$ 39,671**	$ 9,854	**$ 96,584**	$ 42,586
Proceeds from dispositions	**$ 30,132**	$ 1,281	**$ 35,578**	$ 20,984

During the fourth quarter we drilled five (2.45 net) wells, including one (0.75 net) horizontal Montney gas well on our Birley/Umbach property in northeastern British Columbia along with one (0.75 net) horizontal Montney oil well and one (0.50 net) non-operated horizontal Dunvegan oil well in the Grande Prairie area of Alberta. A natural gas well (0.08 net) was sold with our Gilby property disposition during the fourth quarter and a crude oil well (0.38 net) was sold with our Karr property disposition which closed in the first quarter of 2015. A summary of our drilling activities for the current reporting periods is as follows:

	Three months ended December 31, 2014		Year ended December 31, 2014	
	Gross	**Net**	Gross	**Net**
Development wells				
Oil	3.00	**1.62**	9.00	**6.14**
Gas	1.00	**0.08**	2.00	**0.45**
Development wells	4.00	**1.70**	11.00	**6.59**
Exploration gas well	1.00	**0.75**	3.00	**2.25**
Disposal/injection	-	**-**	1.00	**0.37**
Total	5.00	**2.45**	15.00	**9.21**

The Birley/Umbach well (0.75 net) was the third of six (5.0 net) horizontal Montney wells we intend to drill in this area by the end of the first quarter of 2015. We also intend to complete one (0.75 net) of these wells during the first quarter of 2015. A second well (1.0 net) is expected to be completed after spring break-up in anticipation of lower service costs. During the fourth quarter, we also expanded the throughput capacity at our current compression facility from four mmcf/d to approximately nine mmcf/d of gross raw gas. The production from the first two (1.5 net) wells, which averaged 653 boe/d and 782 boe/day over their first 205 and 68 days of production, respectively, in addition to the anticipated production from the two (1.75 net) wells that will be completed during the first half of 2015 is expected to keep the current facility running at or near full capacity through the second half of 2015. We plan on installing a 1.6 kilometre 12 inch gathering line in the first quarter of 2015 and can accelerate the completion of the two (1.75 net) remaining wells, along with drilling an additional three wells (2.5 net) in this area, should both commodity prices and service costs improve in the second half of 2015. Another facility expansion to 35 mmcf/d can also be accelerated with improved commodity prices as the fabrication of equipment will be complete with only installation of the new equipment required to increase capacity.

Our second Montney well (0.75 net) at Gold Creek was drilled and completed during the fourth quarter and had final test rates of 870 boe/d. We anticipate that this well will be placed on-stream during the third quarter of 2015. The first Montney well (0.38 net) was brought on production in November 2014 and averaged 281 bbl/d of crude oil and 3,600 mcf/d of natural gas during its first 82 days of production without artificial lift. The water disposal well (0.37 net) that we drilled in the third quarter of 2013, offsetting this first well is expected to reduce the high operating costs related to trucking water associated with production from the mid-Montney in this area. We anticipate receiving our water disposal permit sometime in the first quarter of 2015. We plan to drill one additional Montney well in Gold Creek in the second half of 2015, subject to completing an assessment of commodity prices and service costs.

At our Albright field, we participated in the drilling and completion of one (0.5 net) non-operated horizontal Dunvegan oil well. The well was brought on production in December 2014 and has averaged 198 bbl/d (gross) over its first 60 days.

Property Acquisition

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

The undeveloped lands were measured at their fair value of $5.0 million using recent market sales transactions of similar undeveloped lands in the immediate surrounding area. When compared with the carrying amount for this undeveloped land of $1.3 million, this resulted in us realizing a gain of $3.7 million as reported through the line item gain on disposition of properties. The decommissioning obligation was measured at its fair value as determined using the timing and estimated costs associated with the abandonment, restoration and reclamation of the acquired wells and infrastructure.

Rationalization of Non-Core Properties

We may from time to time, dispose of properties that are not core to our business strategy in order to provide additional resources and flexibility to focus on our core areas. During the reported year we completed the sale of several petroleum and natural gas properties for aggregate proceeds of $35.6 million. The properties sold included Gilby and portions of Pembina, Monias and Boundary Lake. Our production from these properties was approximately 975 boe/d. The funds from these dispositions were used to partially fund our capital expenditures program of $96.6 million, including the property acquisition of $15.8 million, described above.

Provisions

Decommissioning Obligations

At December 31, 2014, we had decommissioning obligations of $105.9 million for the future abandonment and reclamation of our properties (December 31, 2013 - $85.3 million, related to continuing operations). We estimated the net present value of this total decommissioning obligation based on a total future undiscounted liability of $117.6 million ($123.6 million, including $6.2 million related to discontinued operations - December 31, 2013).

During the reported year, the change in estimate that we reported in our decommissioning obligation of $29.6 million was substantially due to a decrease in the risk-free rate (same period of 2013 – a decrease of $17 million due to higher risk-free rates partially offset by an increase of $6 million due to estimated future abandonment costs). We also incurred additions related to our acquired properties and our Canadian drilling program estimated at $3.0 million (same period of 2013 - $0.6 million) and recorded accretion charges. The recognized accretion charges reflect the increase in the obligation associated with the passage of time. For the current reporting periods, accretion charges of $0.7 million and $2.7 million were comparable to the charges reported during the same periods of 2013.

Partially offsetting these increases in the decommissioning obligation during the reported and comparative years were abandonment and reclamation expenditures related to our Canadian properties of $2.7 million for both periods. In addition, the decommissioning obligation decreased as a result of Canadian property dispositions and the classification of certain properties as held for sale, which removed $11.3 million and $0.8 million of associated decommissioning obligations, respectively (same period of 2013 – $9.5 million and nil, respectively).

As at December 31, 2014 and December 31, 2013, the estimated obligation includes assumptions in respect of actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred, as well as annual inflation of 2.0% in order to calculate the future obligation. At December 31, 2014, a risk-free interest rate of 2.33% was used in order to calculate the present value of the obligation (December 31, 2013 - 3.20%).

Outstanding Share Data

Authorized:

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

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

	December 31 2014	December 31 2013
Common shares outstanding	**215,082,199**	214,187,681
Share options	**10,529,675**	14,319,699
Restricted awards	**206,590**	-
Performance awards	**244,375**	-
Weighted average common shares - basic & dilutive	**214,600,915**	214,187,681

As at March 8, 2015, we had 215,083,496 common shares, 10,285,006 share options, 203,525 restricted awards and 241,310 performance awards outstanding.

Commitments and Guarantees

At December 31, 2014, we had contractual commitments that require the following minimum future payments without giving effect to any offsetting third party agreements which, are anticipated to reduce some of these amounts:

							Year ended December 31
($ thousands)	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
Office leases	$ 1,351	$ 1,370	$ 1,388	$ 1,388	$ 694	$ -	$ 6,192
Operating and transportation contracts	1,165	221	-	-	-	-	1,386
	$ 2,516	**$ 1,591**	**$ 1,388**	**$ 1,388**	**$ 694**	**$ -**	**$ 7,578**

Office lease commitments relate to our head office in Calgary, Alberta. Operating and transport contracts relate to minimal contractual payments regardless if we do not utilize the pipeline capacity or benefit from the operating service.

As at December 31, 2014, we had an outstanding letter of credit totaling $0.3 million to guarantee the services of a Canadian midstream operator. This issued letter of credit reduced the available credit from the Revolving Term Credit Facility.

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

Off Balance Sheet Arrangements

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

Related Party Transactions

We determined that the key management personnel consist of our officers and directors. In addition to the salaries and directors fees paid to the officers and directors respectively, the officers and directors participate in our long-term incentive plans, which include a share option plan and a restricted and performance award incentive plan. The officers' salaries, directors' fees and other benefits as included in general and administrative expenses for the reported and comparable years totaled $2.5 million and $2.4 million, respectively. Long-term incentive benefits for our officers' and directors as included in share-based compensation for the reported and comparable years totaled $0.5 million and $0.8 million, respectively.

The former officers associated with the Discontinued Tunisian Operations were paid salaries plus other benefits and share-based compensation for the reported and comparable years totaling $2.5 million $1.2 million, respectively. For the reported year, this compensation included $1.6 million in severance costs.

Alberta Investment Management Corporation ("AIMCo"), as investment manager to Her Majesty the Queen in Right of the Province of Alberta ("HMQ"), maintains investment control and direction over approximately 37.4% of our outstanding common shares for the benefit of HMQ. Pursuant to a management and administration services agreement (the "Services Agreement") dated June 29, 2010 between 1542991 Alberta Ltd. ("WOGH GP") (a wholly owned subsidiary of our company and the general partner of WOGH Limited Partnership) and our company, WOGH GP engaged our company to perform its duties under the partnership agreement and to manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership in connection with the partnership business and to make all decisions relating thereto. WOGH Limited Partnership was formed to hold working interests in certain of our assets which are held by nominees of AIMCo on behalf of HMQ. As we manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership, we are reimbursed for such services. In accordance with the Services Agreement, we reported a recovery from WOGH Limited Partnership, as reported against our G&A expense, of $1.3 million and $4.0 million for the reported and comparable years. The recovery for the reported and comparative years was generally determined from WOGH Limited Partnership's pro rata share as estimated at 19 percent of its and our combined Canadian production volumes. At December 31, 2014, $0.3 million of this G&A recovery was included in accounts receivable (December 31, 2013 - $0.1 million).

Outlook

The recent decline in commodity prices will make 2015 a challenging year for many oil and gas companies. Notwithstanding our solid financial position and deep inventory of growth projects, we are not immune to these challenges in the near term. During this period of contraction we have embarked on a number of cost saving and optimization initiatives which include shutting-in lower netback production to reduce production expenses and, where warranted, renegotiate and retender service costs. Our guidance for 2015 includes the voluntary shut-in of approximately 500 boe/d of production in 2015. We are confident that these cost saving and optimization initiatives will prove effective in 2015. The transformation of Chinook to a Montney focused domestic company began in 2014. Our pace of Montney development will be prudently managed in 2015 to demonstrate growth from our Montney assets while maintaining a strong balance sheet.

Guidance for 2015 is being provided as follows:

($ millions, except boe/d)		2015 Updated Guidance (1)
Average production (boe/d)		6,600-7,000
Exit production (boe/d)		6,800-7,100
General & administrative expense	$	10.5-11.0
Production & operating expense	$	41.0-43.0
Funds from operations	$	10.0-11.0
Net debt (surplus)	$	34.0-35.0
Capital expenditures	$	44.5

(1) 2015 pricing assumptions: Canadian crude oil of $54.03/bbl; Canadian natural gas of $3.19/mcf.

Selected Annual Information from Continuing Operations

Summarized information by year for the three years ended December 31, 2014, appears below:

Year ended December 31	2014	2013	2012
($ thousands, except per share amounts)			
Petroleum and natural gas revenue, net of royalties	**$ 118,662**	$ 101,433	$ 104,329
Net loss from continuing operations [1]	**$ (50,672)**	$ (9,453)	$ (109,407)
Per share - basic and diluted ($/share)	**$ (0.24)**	$ (0.03)	$ (0.51)
Net loss [1] [2]	**$ (38,400)**	$ (26,700)	$ (91,028)
Per share - basic and diluted ($/share)	**$ (0.18)**	$ (0.12)	$ (0.42)
Total assets [1] [3]	**$ 434,318**	$ 555,341	$ 622,476
Long-term financial liabilities [3] [4]	**$ 106,726**	$ 174,984	$ 209,451

(1) Includes $82.0 million, $3.5 million and $63.5 million in impairment charges against Canadian properties for the years ended December 31, 2012, 2013 and 2014, respectively.

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

(3) Years ended December 31, 2012 and 2013 include the Discontinued Tunisian Operations and their total assets or long-term financial liabilities, as applicable. For the year ended December 31, 2013, the total assets reflect $32.0 million in impairment charges against the Discontinued Tunisian Operations.

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

Factors That Have Caused Variations over the Years

Decreased sales volumes as a result of our non-core property dispositions lowered our petroleum and natural gas revenues, net of royalties during the year ended 2013. This effect was offset during the reported year from results of our successful drilling campaign in northeastern Alberta and northwestern British Columbia and increases in commodity prices.

Our net losses from continuing operations for the years ended 2012, 2013 and 2014 were negatively impacted by impairment charges against our CGUs resulting from decreases in the forward curve of natural gas prices as measured at 2012 and 2013 and the forward curve of crude oil prices as measured at 2014. These impairment charges, in addition to our non-core property disposition program, were greater than our capital expenditures and property acquisitions resulting in a decrease in the carrying value of our total assets in each consecutive year.

Our net loss for the year ended 2013 was also impacted by an additional $32.0 million impairment charge against the Discontinued Tunisian Operations. Further decreasing total assets and long-term financial liabilities in the reported year was the disposition of the Tunisian operations which closed August 19, 2014. Decreases in long-term financial liabilities from the year ended 2012 through to the year ended 2014 primarily resulted from repayments of outstanding debt of $11.0 million and $78.5 million during the years ended 2013 and 2014, respectively. At the end of 2014 there was no outstanding long-term debt.

Please refer to “Continuing Canadian Operations” and other sections of this MD&A for detailed discussions on variations during the comparative year ended and to our previous annual management’s discussion and analysis for changes in the prior year.

Quarterly Information from Continuing Operations

Summarized information by quarter for the two years ended December 31, 2014, appears below:

	Dec. 31 2014	Sep. 30 2014	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	Jun. 30 2013	Mar. 31 2013
CONTINUING CANADIAN OPERATIONS								
Production Volumes								
Crude Oil (bbl/d)	**1,981**	1,823	2,267	2,084	1,840	1,853	1,606	1,549
Natural gas liquids (boe/d)	**778**	678	715	950	722	753	874	1,005
Natural gas (mcf/d)	**34,879**	29,028	29,570	29,364	32,287	34,563	33,226	36,468
Average daily production (boe/d)	**8,572**	7,339	7,911	7,928	7,943	8,367	8,018	8,633
Sales Prices								
Average oil price ($/bbl)	**$ 70.84**	$ 93.10	$ 101.01	$ 96.41	$ 81.18	$ 97.53	$ 92.43	$ 82.65
Average natural gas liquids price ($/boe)	**$ 48.05**	$ 64.71	$ 72.06	$ 74.10	$ 63.74	$ 62.36	$ 55.06	$ 58.85
Average natural gas price ($/mcf)	**$ 3.57**	$ 4.11	$ 4.89	$ 6.01	$ 3.57	$ 2.55	$ 3.74	$ 3.34
Netback (1)								
Average commodity pricing ($/boe)	**$ 35.26**	$ 45.37	$ 53.75	$ 56.50	$ 39.09	$ 37.76	$ 40.02	$ 35.80
Royalties ($/boe)	**$ (4.74)**	$ (6.90)	$ (8.47)	$ (6.01)	$ (4.80)	$ (3.53)	$ (5.23)	$ (4.08)
Net production expenses ($/boe) (1)	**$ (18.89)**	$ (17.44)	$ (17.06)	$ (16.91)	$ (15.83)	$ (16.42)	$ (15.55)	$ (14.96)
G&A expense ($/boe)	**$ (4.26)**	$ (4.32)	$ (4.30)	$ (6.46)	$ (3.47)	$ (1.71)	$ (2.76)	$ (3.07)
Netback ($/boe) (1)	**$ 7.37**	$ 16.71	$ 23.92	$ 27.12	$ 14.99	$ 16.10	$ 16.48	$ 13.69
Wells Drilled (net)								
Oil	**1.62**	1.26	-	3.26	1.65	3.00	-	3.61
Gas	**0.83**	0.75	-	1.12	-	-	-	-
Disposal/injection	**-**	0.37	-	-	-	-	-	-
Total wells drilled (net)	**2.45**	2.38	-	4.38	1.65	3.00	-	3.61
amounts)								
Petroleum & natural gas revenues, net of royalties	**$ 24,065**	$ 25,972	$ 32,596	$ 36,029	$ 25,055	$ 26,347	$ 25,385	$ 24,646
Funds from operations (1)	**$ 6,069**	$ 9,693	$ 14,801	$ 17,594	$ 8,786	$ 12,213	$ 10,662	$ 9,453
Per share - basic and diluted ($/share)	**$ 0.03**	$ 0.05	$ 0.07	$ 0.08	$ 0.04	$ 0.06	$ 0.05	$ 0.04
Net (loss) income from continuing operations (2)	**$ (58,311)**	$ 3,696	$ 3,533	$ 410	$ (10,151)	$ (316)	$ 3,682	$ (2,668)
Per share - basic and diluted ($/share)	**$ (0.27)**	$ 0.02	$ 0.02	$ 0.00	$ (0.05)	$ (0.00)	$ 0.02	$ (0.01)
Net (loss) income (2)(3)(4)	**$ (60,348)**	$ 11,472	$ 4,391	$ 6,085	$ (39,002)	$ 3,812	$ 3,989	$ 4,500
Per share - basic and diluted ($/share)	**$ (0.28)**	$ 0.05	$ 0.02	$ 0.03	$ (0.18)	$ 0.02	$ 0.02	$ 0.02
Capital expenditures and business combination	**$ 39,671**	$ 14,301	$ 18,998	$ 23,614	$ 9,854	$ 10,014	$ 5,506	$ 17,212
Net debt (surplus) (1) (5)	**$ (28,788)**	$ (35,870)	$ 80,536	$ 74,390	$ 61,849	$ 65,105	$ 66,340	$ 64,440
Total assets (5)	**$ 434,318**	$ 472,241	$ 589,515	$ 604,419	$ 555,341	$ 593,192	$ 621,143	$ 617,459
Common Shares (thousands)								
Weighted average during period - basic	**215,081**	214,895	214,226	214,188	214,188	214,188	214,188	214,188
Weighted average during period - diluted	**215,081**	216,773	215,814	214,245	214,188	214,188	214,188	214,188
Outstanding at period end	**215,082**	215,079	214,674	214,188	214,188	214,188	214,188	214,188

(1) Funds from operations, funds from operations per share, net debt (surplus), netback and net production expense are non-IFRS measures as defined and calculated throughout this MD&A. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

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

(3) Includes net income from discontinued operations where we also reported $32.0 million in impairment charges against the Discontinued Tunisian Operations for the three months ended December 31, 2013.

(4) Significant crude oil production from the Discontinued Tunisian Operations of 88,000 barrels and 36,000 barrels was not sold at March 31, 2013 and June 30, 2014, respectively.

(5) Quarters prior to the three months ended September 30, 2014 include the Discontinued Tunisian 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, which continued through 2014, resulted in a lower trend of natural gas and natural gas liquids production volumes until the fourth quarter when we began to realize continuous production from our drilling program 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 partial reinvestment of our non-core disposition proceeds into core area crude oil properties. Our realized commodity prices and natural gas revenue, net of royalties have mostly trended with the Canadian Light Sweet and AECO Gas benchmarks which generally increased until mid-2014 when they began to decline. The higher trending revenue net of royalties through 2013 as well as the increasing proportion of total volumes from crude oil production and this commodity's higher associated netback generated sufficient cash flow to generally reduce our net debt throughout 2013. An increase in capital expenditures, including sizeable Montney land acquisitions, started to increase net debt in 2014 until the third quarter where a portion of the proceeds from the Tunisian Disposition Transaction financed the repayment of our entire outstanding debt balance. Our disposition of non-core assets and our management of organic growth and business acquisitions relative to our existing cash flows 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 ("AIF") and below 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 and below 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".

Exploration, Development and Production Risks

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

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in a liability to us.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

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

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance our reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions, in the United States, Canada and Europe, the actions of the Organization of the Petroleum Exporting Countries (“OPEC”), governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect our ability to obtain equity or debt financing on acceptable terms.

Market Price of Common Shares

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

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

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;

- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Gathering and Processing Facilities and Pipeline Systems

We deliver our products through gathering and processing facilities and pipeline systems some of which we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on our ability to process our production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than us. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

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

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases and which may require us to comply with greenhouse gas ("GHG") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of our reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, our access to additional financing may be affected.

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

Credit Facility Arrangements

The amount authorized under the Revolving Term Credit Facility is dependent on the borrowing base determined by the lenders. We are required to comply with covenants under our Revolving Term Credit Facility which include, certain financial ratio test and certain revenue and expenditure (including debt service) coverage ratio tests and, which may, from time to time, either affect the availability, or price, of existing and/or additional funding under the Revolving Term Credit Facility. In the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to the failure of us to comply with these covenants. A failure to comply with the applicable covenants (including the financial and coverage ratio tests) could result in default under the Revolving Term Credit Facility which could result in us being required to repay amounts owing thereunder. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to us. If we are unable to repay amounts owing under our Revolving Term Credit Facility, the lenders under our Revolving Term Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The Revolving Term Credit Facility is secured by our consolidated Canadian assets. The acceleration of our indebtedness under the Revolving Term Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Revolving Term Credit Facility may impose operating and financial restrictions on us that could include restrictions on paying dividends or repurchasing or making of other distributions with respect to our securities, incurring of additional indebtedness, providing guarantees, assuming loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Revolving Term Credit Facility lenders use our consolidated Canadian reserves, commodity prices, applicable discount rates and other factors, to periodically determine the borrowing base under the Revolving Term Credit Facility. A material decline in commodity prices could reduce the borrowing base under the Revolving Term Credit Facility, reducing the funds available to us under the credit facility. This could result in the requirement to repay a portion, or all, of our indebtedness thereunder.

Issuance of Debt

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

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, we will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

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

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Control by Principal Shareholder

Her Majesty the Queen in Right of the Province of Alberta ("HMQ") owns 80,357,142 common shares, representing approximately 37.4% of our current outstanding common shares. Alberta Investment Management Corporation ("AIMCo"), as investment manager to HMQ, maintains investment control and direction over the common shares for the benefit of HMQ. Accordingly, AIMCo will have significant influence over our business and affairs and may have the ability to take shareholder actions irrespective of the vote of any other shareholders, including the ability to prevent certain transactions that it does not believe are in HMQ's best interest. This significant influence may discourage transactions involving a change of control of our company, including transactions in which our minority shareholders might otherwise receive a premium for the common shares over the then-current market price.

Furthermore, AIMCo will generally have the right (subject to applicable securities laws) at any time to sell the common shares held by HMQ or to sell HMQ's interest in us to a third party without the approval of our minority shareholders and without providing for a purchase of such shareholders' shares. Accordingly, the common shares held by our minority shareholders may be less liquid and worth less than they would be if AIMCo did not have the ability to influence matters affecting us.

Geopolitical Risks

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

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

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

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects.

Breach of Confidentiality

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

Income Taxes

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

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

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Conflicts of Interest

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

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect for us. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Expansion into New Activities

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

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

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

Management Judgment and Estimation Uncertainty

The preparation of the Financial Statements requires judgments and estimation uncertainty that affect the reported amounts at the date of the Financial Statements of assets, liabilities, shareholders' equity, revenues and expenses in addition to the disclosure of contingencies. Actual results could differ from those estimated. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Judgments that management has made through applying accounting policies that have the most significant effect on the Financial Statements are discussed below:

Cash Generating Units

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or group of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors Chinook's operations.

Impairment indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. When assessing the recoverability of petroleum and natural gas properties, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less cost to sell and value in use. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on reserve estimates, market value of undeveloped lands and other relevant assumptions.

Key estimates that management has made that affect the measurement of balances and transactions are discussed below:

Reserve estimates

Petroleum and natural gas reserves are used in the calculation of depletion, impairment and impairment reversals. Reserve estimates and their resulting cash flows are based on engineering data, probability assessments of reserve recoveries, future prices and costs, future production rates, discount rates and the timing and extent of future capital expenditures, all of which are subject to many uncertainties and interpretation. We expect that over time our reserve estimates will be revised, either upward or downward, based on updated information such as the results of future drilling, testing and production levels and changes to forward petroleum and natural prices and production costs.

Decommissioning obligation

Decommissioning obligations are recognized for the future decommissioning and restoration of property, plant and equipment. These obligations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Deferred taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which we operate are subject to change. The deferred tax asset and/or liability is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized from future taxable earnings.

Foreign currency

Prior to the completion of the Tunisian Disposition Transaction on August 19, 2014, SVI Barbados and its wholly-owned subsidiary's functional currency required assessing several factors, including the dominant currency used in transactions such as the settlement of revenues and operational and capital expenditures.

New Accounting Standards and Amendments

New Accounting Standards Not Yet Adopted

In July 2014, the IASB issued IFRS 9 “Financial Instruments” to replace IAS 39, “Financial Instruments Recognition and Measurement”. The new standard replaces the current multiple classification and measurement models for financial instruments with a single model that has only two classifications categories: amortized cost and fair value. As of January 1, 2018, we will be required to adopt this standard. We are evaluating the impact this standard may have on our consolidated financial statements.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. We are evaluating the impact this standard may have on our consolidated financial statements.

New Accounting Amendments and Interpretation

We adopted the following new amendments and interpretation:

Amendments to IAS 32, Financial Instruments: Presentation,

Amendments to IAS 36, Impairment of Assets, and

IFRS Interpretation Committee (“IFRIC”) 21, Levies.

The adoption of these amendments and interpretation had no material impact on our financial results recorded in the Financial Statements as at December 31, 2014.

Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to us is made known to our CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of our disclosure controls and procedures at December 31, 2014 and have concluded that our disclosure controls and procedures are effective at December 31, 2014.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in our internal controls over financial reporting were identified during the period beginning on October 1, 2014 and ended on December 31, 2014, that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting. Our CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of our internal controls over financial reporting at December 31, 2014 and have concluded that our internal controls over financial reporting are effective at December 31, 2014.

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

It should be noted that a control system, including our disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Other Information

Forward-Looking Statements

In the interest of providing our shareholders and readers with information regarding our company, including management's assessment of our future plans and operations, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: expectations regarding future reductions in operating and G&A costs, budgeted amounts in fiscal 2015, expectations that such amounts will be spent in the manner, location and timeframes set forth herein, expectations as to how we will fund the 2015 capital program, future exploration and development activities and the timing thereof, as well as our expectations regarding production, general and administrative expenses, production and operating expenses, funds from operations, net debt (surplus) and capital expenditures set out in 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 debt and cash flow to fund our planned expenditures. Although we believe that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, our Board of Directors may amend the 2015 capital program based on its discretion; environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increased or unforeseen capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Barrels of Oil Equivalent

Barrels of oil equivalent (boe) is calculated using the conversion factor of 6 mcf (thousand cubic feet) of natural gas being equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl (barrel) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Initial Production Levels

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

Future Oriented Financial Information

This MD&A, in particular the information in respect of anticipated cash flows, 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.