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 three months ended March 31, 2014 and 2013 and should be read in conjunction with our condensed consolidated financial statements and accompanying notes as at and for the three months ended March 31, 2014 and 2013 and the consolidated financial statements and accompanying notes as at and for the years ended December 31, 2013 and 2012. This MD&A is based on information available as at May 13, 2014.

The term "first quarter" or similar terms are used throughout this document and refer to the three months ended March 31, 2014. The term "same quarter of 2013" or similar terms are used throughout this document and refer to the three months ended March 31, 2013.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2013 ("AIF"), can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The condensed consolidated financial statements and comparative information for the three months ended March 31, 2014 and 2013 have been prepared in accordance with International Accounting Standard ("IAS") 34 'Interim Financial Reporting' using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board. The condensed consolidated financial statements include the accounts of our direct and indirect subsidiaries all of which are wholly owned. 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 cash flow, cash flow per share, netback, net debt, net production expense, cash G&A, 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 crude oil and natural gas exploration and development company with crude oil, natural gas and liquids reserves in western Canada and predominately crude oil reserves in Tunisia, North Africa. We are incorporated under the laws of the Province of Alberta, Canada. Our common shares are listed 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.

Our operating and reportable segments are as follows:

- Canada – includes our Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in northwestern Alberta and northeastern British Columbia.
- Tunisia – includes eight blocks totaling 2.6 million gross acres located offshore in the Gulf of Hammamet within the Pelagian Basin (Cosmos, Yasmin) and onshore within the Ghadames Basin (Bir Ben Tartar and Adam producing properties and undeveloped onshore blocks).
- Corporate – includes derivative transactions, general and administrative costs and assets held corporately.

Segmented financial information is presented after the elimination of intercompany transactions.

Forward-Looking Information

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

Financial and Operating Highlights

Three months ended March 31	2014	2013
OPERATIONS		
Production		
Oil *(bbl/d)*	**3,672**	3,565
Natural gas liquids *(bbl/d)*	**950**	1,005
Natural gas *(mcf/d)*	**30,839**	37,736
Average daily production *(boe/d)*	**9,761**	10,860
Sales		
Oil *(bbl/d)*	**3,707**	2,710
Natural gas liquids *(bbl/d)*	**950**	1,005
Natural gas *(mcf/d)*	**30,839**	37,736
Average daily production *(boe/d)*	**9,797**	10,006
Sales Price		
Average oil price *($/bbl)*	**$ 105.83**	$ 95.03
Average natural gas liquids price *($/bbl)*	**$ 74.10**	$ 58.85
Average natural gas price *($/mcf)*	**$ 6.42**	$ 3.72
Netback(1)		
Average commodity pricing *($/boe)*	**$ 67.44**	$ 45.70
Royalties *($/boe)*	**$ (5.57)**	$ (3.79)
Net production expenses *($/boe)*(1)	**$ (19.44)**	$ (16.52)
Cash G&A *($/boe)*(1)	**$ (5.91)**	$ (2.83)
Netback *($/boe)*(1)	**$ 36.52**	$ 22.56
Wells Drilled *(net)*		
Oil	**6.70**	3.61
Gas	**1.12**	-
Total wells drilled *(net)*	**7.82**	3.61
FINANCIAL *($ thousands, except per share amounts)*		
Petroleum & natural gas revenues, net of royalties	**$ 54,545**	$ 37,740
Cash flow(1)	**$ 28,449**	$ 21,518
Per share - basic and diluted *($/share)*	**$ 0.13**	$ 0.10
Net income	**$ 6,085**	$ 4,500
Per share - basic and diluted *($/share)*	**$ 0.03**	$ 0.02
Capital expenditures	**$ 40,391**	$ 25,046
Net debt(1)	**$ 74,390**	$ 64,440
Total assets	**$ 604,419**	$ 617,459
Common Shares *(thousands)*		
Weighted average during period		
- basic	**214,188**	214,188
- diluted	**214,245**	214,188
Outstanding at period end	**214,188**	214,188

(1) Cash flow, cash flow per share, net debt, netback, net production expense and cash G&A 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.

Operations

Petroleum and Natural Gas Production and Sales Volumes

Three months ended March 31				2014				2013
	Oil	Natural Gas Liquids	Natural Gas	Total[(1)]	Oil	Natural Gas Liquids	Natural Gas	Total[(1)]
	(bbl/d)	*(bbl/d)*	*(mcf/d)*	*(boe/d)*	*(bbl/d)*	*(bbl/d)*	*(mcf/d)*	*(boe/d)*
Production								
Canada	**2,084**	**950**	**29,364**	**7,928**	1,549	1,005	36,468	8,633
Tunisia	**1,588**	**-**	**1,475**	**1,833**	2,016	-	1,268	2,227
Total[(1)]	**3,672**	**950**	**30,839**	**9,761**	3,565	1,005	37,736	10,860
Sales								
Canada	**2,084**	**950**	**29,364**	**7,928**	1,549	1,005	36,468	8,633
Tunisia	**1,623**	**-**	**1,475**	**1,869**	1,161	-	1,268	1,373
Total[(1)]	**3,707**	**950**	**30,839**	**9,797**	2,710	1,005	37,736	10,006

(1) Totals may not be additive as a result of rounding.

Our first quarter Canadian crude oil production achieved its highest production level since the first quarter of 2012. Crude oil production during the first quarter increased by 535 barrels of oil per day ("bopd") compared to the same quarter of 2013, despite the first quarter including a prior period reclassification of 190 barrels of oil equivalent per day ("boepd") from crude oil to natural gas liquids volumes, which had no impact on petroleum revenues. Our 2013 drilling campaign was focused on the development of our crude oil properties which included Albright, Karr, and a Montney prospect at Gold Creek. This focus continued during the first quarter when we drilled and completed five (3.63 net) wells on these properties and one (0.75 net) Montney well in the Birley area, in addition to completing two (0.87 net) wells that were drilled during the fourth quarter of 2013 in the Albright and Karr areas.

Our Canadian segment's drilling and completion expenditures for the first quarter totaled $18.4 million (same quarter of 2013 - $10.6 million). Our crude oil production during the first quarter increased 35% over the same quarter of 2013; however, the overall production level of our Canadian segment decreased 705 boepd, compared to the same quarter of 2013. This decrease included approximately 600 boepd of production associated with non-core property dispositions made during 2013, in addition to natural reservoir production declines.

During April 2014, the Montney prospect at Gold Creek (0.37 net) was tested for seven days with final gross production rates of 554 bopd plus 3,300 thousand cubic feet per day ("mcfpd") of natural gas (total 1,107 boepd) having recovered 25% of the total load fluid to that point. Testing extended into spring break-up, making trucking of the total produced fluid a logistical challenge. As a result, we decided to suspend testing until post break-up at which time an extended well test will take place. Pipeline construction to tie-in the natural gas production into a company owned facility is nearly complete and planning for the necessary well site, fluid handling and disposal facilities is underway. We cannot predict a production rate or on stream date for this well until the well is fully tested.

Our first quarter's Tunisian production volumes of 1,833 boepd decreased 18% relative to the same quarter of 2013. Our Tunisian production volumes are primarily generated from our development of our Bir Ben Tartar ("BBT") Concession. In the latter half of 2013, we were informed by the Tunisian Regulatory Authority that a new application and approval process, that better addressed the risk to ground water and the mitigating measures we were taking to protect this resource, would be required by the Agence Nationale de Protection de l'Environnement ("ANPE") prior to the receipt of approvals for more well locations on the BBT Concession. This new application work was completed in cooperation and with the support of the Entreprise Tunisienne d'Activités Pétrolières ("ETAP") and the Tunisian petroleum authority, Direction Générale de l'Energie ("DGE") and was submitted during the fourth quarter of 2013. Once this application was approved late in 2013 we were able to recommence our drilling program. However, the delay resulted in less new production being added during the first quarter to offset natural production declines.

During the first quarter, we drilled four vertical wells (3.44 net) and completed three vertical wells (2.58 net) on our BBT Concession. Because these newly drilled wells were brought on production late in the first quarter, net incremental production volumes from this drilling activity during the first quarter was nominal. However, the combined initial test net production rates over 10 days from the three newly drilled and completed wells was 470 bopd. Each of these wells was drilled and completed for gross costs of approximately $4.0 million (0.86 net). Our first quarter Tunisian segment's drilling and completion expenditures were $15.7 million (same quarter of 2013 - $4.0 million), which also included a portion of the completion costs on the fourth well, costs associated with preparing the remaining two drilling sites including the associated materials, the costs to complete a workover of our TT12 well to convert it to a water injection well, jet pumps and the optimization of production rates.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended March 31			2014			2013
($ thousands, except per unit amounts)	Canada	Tunisia	Total[1]	Canada	Tunisia	Total[1]
Oil sales	**$ 18,087**	**$ 17,224**	**$ 35,311**	$ 11,524	$ 11,657	$ 23,181
$/bbl	**96.41**	**117.91**	**105.83**	82.65	111.54	95.03
Natural gas liquids sales	**$ 6,333**	**$ -**	**$ 6,333**	$ 5,325	$ -	$ 5,325
$/bbl	**74.10**	**-**	**74.10**	58.85	-	58.85
Natural gas sales	**$ 15,894**	**$ 1,921**	**$ 17,815**	$ 10,970	$ 1,678	$ 12,649
$/mcf	**6.01**	**14.48**	**6.42**	3.34	14.71	3.72
Petroleum and natural gas revenue	**$ 40,314**	**$ 19,145**	**$ 59,459**	$ 27,819	$ 13,336	$ 41,155
$/boe	**56.50**	**113.83**	**67.44**	35.80	107.96	45.70

(1) Totals may not be additive as a result of rounding.

Petroleum and natural gas revenues during the first quarter of $59.5 million increased $18.3 million from the same quarter of 2013. This increase was due to the higher realized weighted average commodities price combined with an increase in Canadian and Tunisian crude oil sales volumes. During the first quarter, Tunisian crude oil sales volumes approximated those produced whereas during the comparative quarter we waited for a tanker to take delivery of the 88,000 barrels of crude oil production that was held in inventory.

Canadian Petroleum and Natural Gas Revenue and Prices

Our Canadian petroleum and natural gas revenue during the first quarter of $40.3 million increased $12.5 million from the same quarter of 2013. This increase resulted from both higher realized commodities pricing and crude oil sales volumes. Higher crude oil sales volumes were the result of the focused development of our crude oil properties located in northwestern Alberta. Our Canadian segment's ratio of crude oil production, which has a higher associated price per boe, increased compared to this segment's total produced volumes to 26% in the first quarter compared to 18% in the same quarter of 2013.

Tunisian Petroleum and Natural Gas Revenue and Prices

Our Tunisian petroleum and natural gas revenue for the first quarter increased compared to the same quarter of 2013. This increase was due to higher sales volumes and a higher reported crude oil price despite a weakening in the underlying Brent benchmark price. Crude oil revenue and sales volumes for the comparative quarter were affected by the 88,000 barrels of crude oil production that was held in inventory as we were waiting for a tanker to take delivery.

The difference between our Tunisian production and sales volumes results from crude oil wellhead production being measured in the field versus sales recognition being measured at the point when crude oil is loaded onto a tanker and transfer of title has occurred. The portion of crude oil production that is either in transit from the wellheads or is being stored at terminal facilities awaiting delivery to shipping tankers at each reporting date is reported as inventory.

Benchmark Prices

Three months ended March 31	2014	2013
Oil		
Edmonton par ($/bbl)	**$ 99.79**	$ 88.21
Brent ($US/bbl)	**$ 107.90**	$ 112.55
Natural gas liquids		
WTI[1] ($US/bbl)	**$ 98.68**	$ 94.37
Natural gas		
AECO ($/mcf)	**$ 5.80**	$ 3.25

(1) West Texas Intermediate

All of our produced Canadian commodities showed notable benchmark price increases during the first quarter compared to the same quarter of 2013. Increases in North American natural gas prices were attributed to a colder than expected winter, particularly in the eastern half of North America, which resulted in larger than expected withdrawals from natural gas storage facilities. This, along with an increased recovery in the US economy, caused a greater demand for petroleum and natural gas products resulting in an increase of North American benchmark prices.

Crude Oil Pricing

Our average realized crude oil sales price for the first quarter of $105.83 per barrel increased from $95.03 per barrel during the same quarter of 2013.

Our Canadian conventional crude oil production is sold at prices based on the Edmonton par benchmark postings as adjusted for quality. This benchmark increased during the first quarter, as did our average realized Canadian crude oil price, compared to the same quarter of 2013.

Our Tunisian crude oil production is sold at the three day average price for Brent oil quotations after being loaded onto a shipping tanker. Consistent with the decrease in the Brent benchmark, our realized US dollar denominated Tunisian crude oil price was lower during the first quarter, compared to the same quarter of 2013, but was higher when reported in Canadian dollars due to the relative strengthening of the US dollar.

Natural Gas Liquids Pricing

Our Canadian 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. Our realized natural gas liquids price of $74.10 per barrel was higher than the same quarter of 2013. There are various benchmarks for natural gas liquids, depending on the type sold; however we benchmark our liquids in reference to Edmonton par or WTI pricing. Relative to Edmonton par, our realized natural gas liquids price for the first quarter increased to 74% from 67% in the same quarter of 2013. Increases in the realized prices for ethane and propane condensates in excess of the higher Edmonton par benchmark explain the higher natural gas liquids price and ratio relative to Edmonton par.

Natural Gas Pricing

Our Canadian realized natural gas price of $6.01 per mcf for the first quarter showed significant improvement from the $3.34 per mcf reported for the same quarter of 2013. Our Canadian realized natural gas price reflects the increase in the AECO benchmark price.

Managing Commodity Price Risk

We attempt to mitigate commodity price risk through the use of financial derivative contracts. See “Commodity Price Risk Management Contracts” for a further discussion on our financial derivative contracts.

Royalties

Three months ended March 31			2014			2013
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 4,285**	**$ 629**	**$ 4,914**	$ 3,172	$ 243	$ 3,415
Per sales ($/boe)	**$ 6.01**	**$ 3.74**	**$ 5.57**	$ 4.08	$ 1.96	$ 3.79
Percent of Revenues (%)	**11**	**3**	**8**	11	2	8

During the first quarter, our royalties of $4.9 million increased relative to the same quarter of 2013 due to higher petroleum and natural gas revenues. This increase in revenues partially resulted from higher realized commodity pricing which led to higher royalties on a boe basis. Our Tunisian royalties, overall and on a boe basis, were also affected by the relative strengthening of the US dollar. Overall and on a segment basis, our royalties as a percent of revenue during the first quarter were consistent with those reported in the same quarter of 2013. Our Tunisian segment’s royalties result from sales volumes produced from our Adam Concession. We are presently paying an average royalty rate of 9% for natural gas and 12% for crude oil on this Concession’s sales volumes. We do not pay royalties on our Tunisian BBT Concession’s sales volume which is governed by a production sharing contract between ourselves and ETAP.

Production and Operating Expense

Three months ended March 31			2014			2013
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating	**$ 13,381**	**$ 5,075**	**$ 18,456**	$ 15,020	$ 3,259	$ 18,279
Less:						
Processing & gathering revenues	**(1,318)**	**-**	**(1,318)**	(3,399)	-	(3,399)
Net production & operating expense[(1)]	**$ 12,063**	**$ 5,075**	**$ 17,138**	$ 11,621	$ 3,259	$ 14,880
Per sales net production & operating expenses ($/boe)[(1)]	**$ 16.91**	**$ 30.17**	**$ 19.44**	$ 14.96	$ 26.38	$ 16.52
Per sales production & operating expenses ($/boe)	**$ 18.75**	**$ 30.17**	**$ 20.93**	$ 19.33	$ 26.38	$ 20.30

(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 $18.5 million for the first quarter was relatively consistent with the same quarter of 2013 as decreases in our Canadian segment's costs were offset by increases from our Tunisian segment.

The decrease in our Canadian segment's production and operating costs resulted from our property dispositions during 2013 which caused lower sales volumes. These property dispositions were mostly associated with non-operated natural gas sales volumes for which we were charged higher operating costs on an average and boe basis. The effect of these dispositions was a decrease in our operating costs per boe. However, despite this decrease, a shift to higher crude oil production has put increased upward pressure on our operating costs, as crude oil is generally produced at a higher operating cost per barrel. Going forward, since we operate our core Albright crude oil production property, we will be better able to manage our operating cost structure. The decrease in operating expense was also exaggerated by the comparative quarter's production expense which included $0.6 million of adjustments to reconcile previous estimates including a non-operated equalization for higher throughput of volumes.

In Tunisia, the increase in sales volumes during the first quarter, when combined with the relative strengthening of the US dollar, resulted in higher production and operating costs compared to the same quarter of 2013. Increased costs for equipment rentals also increased our first quarter production and operating expenses, on an overall and boe basis, compared to the same quarter of 2013. Partially offsetting these increases were lower oil trucking costs resulting from a new contract that we negotiated at the end of 2013.

In the first quarter, we started to lower our Tunisian BBT operating costs on a boe basis in comparison the fourth quarter of 2013 as a result of lower costs for rental equipment and water handling/hauling. Lower equipment rental costs resulted from purchasing jet pump systems. These systems are installed when an individual well's production declines to the point of requiring some form of artificial lift. Jet pump systems are preferred over pumpjacks in Tunisia as they do not require servicing by a rig. Lower water handling/hauling costs resulted from the shut-in of our TT12 well which introduced produced water from our BBT reservoir. This well has already been converted to a water injector and is scheduled to come on-stream in parallel to our new water treatment facility in the latter half of 2014. Based on performed simulation work, water injection into the TT12 horizontal well is expected to provide a significant increase in oil recoveries from the modelled area.

Canadian processing and gathering revenue decreased for the first quarter compared to the same quarter of 2013. During the comparative quarter we reported higher throughput of third party volumes though our processing facilities and distribution pipelines.

General & Administrative ("G&A") Expense

Three months ended March 31	2014	2013
($ thousands, except per unit amounts)		
G&A expense	**$ 5,165**	$ 2,722
Add back/(deduct):		
Share-based compensation	**(194)**	(435)
Provision for bad debts	**(20)**	-
Amortization of deferred lease liability	**264**	264
Cash G&A expense[(1)]	**$ 5,215**	$ 2,551
Per sales ($/boe)	**$ 5.91**	$ 2.83

(1) Cash G&A is a non-IFRS measure and is calculated as G&A expense less share-based compensation, non-cash changes in the provision for bad debt and the amortization of the deferred lease liability. Management uses this non-IFRS measure to assist them in understanding the current periods' cash cost of G&A expenses.

G&A expense for the first quarter increased compared to the same quarter of 2013. This was due to the reporting of $1.1 million of accrued incentive compensation for our employees and officers and lower reported overhead recoveries, mostly from our joint venture partners. The increase in the weighted average working interest of our current operated activities has lowered our overhead recoveries from our partners. These changes increased cash G&A and, when combined with lower sales volumes, the effect was a further increase in the reported cash G&A on a boe basis. For the fiscal year ended 2014, we expect cash G&A to average $4.19 per boe.

Netback

The following table outlines the netback[(1)] by country and on a consolidated basis:

Three months ended March 31			2014			2013
Per sales ($/boe)	Canada[(2)]	Tunisia	Total	Canada[(2)]	Tunisia	Total
Realized sales price	**$ 56.50**	**$ 113.83**	**$ 67.44**	$ 35.80	$ 107.96	$ 45.70
Less:						
Royalties	**(6.01)**	**(3.74)**	**(5.57)**	(4.08)	(1.96)	(3.79)
Net production expense[(3)]	**(16.91)**	**(30.17)**	**(19.44)**	(14.96)	(26.38)	(16.52)
Cash G&A[(4)]	**(6.46)**	**(3.56)**	**(5.91)**	(3.07)	(1.35)	(2.83)
Netback[(1)]	**$ 27.12**	**$ 76.36**	**$ 36.52**	$ 13.69	$ 78.27	$ 22.56

(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 cash G&A, 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) Canada also includes all corporate G&A expenses associated with the head office.

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

(4) See the G&A expense table where this non-IFRS measure is defined.

Our netback for the first quarter increased 62% compared to the same quarter of 2013. This increase was due to a 98% higher netback from our Canadian segment combined with an increase in the proportion of our total sales volumes contributed from our Tunisian segment with its higher associated netback. The first quarter's netback, on a boe basis, of $36.52 was over one-half of the average realized sales price which was an improvement over the same quarter in 2013.

Contributing to the increase in our Canadian netback per boe was a higher realized crude oil price and a higher proportion of crude oil sales volumes. This increase in the proportion of our Canadian crude oil resulted from our focus on the development of our crude oil weighted properties and the continued disposition of dry natural gas properties throughout 2013. We achieve a higher realized sales price per barrel on our Canadian crude oil sales than we do on an equivalent boe of natural gas resulting in an increased netback. The increase in the Canadian netback also resulted from higher natural gas pricing, including the pricing realized for the associated liquids. Although an equivalent boe of natural gas continues to sell at a significant discount relative to a barrel of oil, we realized an 80% increase in our Canadian natural gas price during the first quarter of 2014 compared to the same quarter of 2013. In comparison to the fourth quarter of 2013, and for the same reasons already noted, we realized an 80% increase in our Canadian netback. The first quarter's Canadian netback includes cash G&A costs related to our corporate office of approximately $4.97 per boe compared to $1.50 per boe in the same quarter of 2013. This increase resulted from lower sales volumes and overhead recoveries combined with accrued incentive compensation.

Although we realized a significant Tunisian netback of $76.36 per boe during the first quarter, we reported a modest decrease compared to the same quarter of 2013, despite the relative strengthening of the US dollar. This decrease, on a US dollar and boe basis resulted from the lower Brent benchmark price combined with higher royalties, net production and cash G&A expenses.

Exploration and Evaluation Expense

Three months ended March 31	2014	2013
($ thousands)		
Canada	**$ 469**	$ 3,098
Tunisia	**405**	1,401
Total	**$ 874**	$ 4,499

Exploration and evaluation expense for the first quarter decreased to $0.9 million from $4.5 million during the same quarter of 2013. For the first quarter, this expense was entirely due to Canadian and Tunisian pre-licensing evaluation, exploratory lease rental and geological and geophysical costs. The comparative quarter's expense included $3.1 million of pre-licensing evaluation, exploratory lease rental and geological and geophysical costs, including costs related to a 3D seismic study over our Borj El Khadra onshore Tunisian exploration permit. In addition, during the comparable quarter we continued our evaluation and determined that a Canadian exploration well that was drilled in 2012 was unsuccessful for petroleum and/or natural gas reserves. Costs incurred on this Canadian exploratory well of $1.4 million were expensed during the first quarter of 2013 through exploration and evaluation expense.

Risk Management Contract Losses

Three months ended March 31	2014	2013
($ thousands)		
Realized loss on derivative contracts	**$ 1,192**	$ 11
Unrealized loss on derivative contracts	**3,307**	593
Total	**$ 4,499**	$ 604

We use commodity price risk management contracts to reduce our exposure to fluctuations in commodity prices. We present the fair value of derivative contracts without offsetting by counterparty on the condensed consolidated statements of financial position. Our swap and collar commodity price contracts reported 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 notional volumes during the remaining periods.

For the first quarter, we realized losses on our AECO and WTI derivative contracts as these benchmark prices averaged above our received fixed price contracts. If we had included these settlements in our commodity revenues, we would have reported adjusted sales prices of $6.12 per mcf and $104.77 per barrel for natural gas and crude oil, respectively, compared to our reported prices of $6.42 per mcf and $105.86 per barrel. Our Brent benchmark indexed collar contract resulted in only a nominal realized loss during the first quarter.

Our unrealized losses for the first quarter resulted from our AECO and WTI benchmarked indexed derivative contracts outstanding on March 31, 2014. Since last measured on December 31, 2013, these forward benchmark prices have increased. Partially offsetting these unrealized losses, the forward Brent benchmark price has decreased.

Net Financing Expense

Three months ended March 31	2014	2013
($ thousands)		
Interest on bank debt	**$ 777**	$ 1,275
Interest earned	**(130)**	(299)
Finance charges and fees	**199**	72
Amortization of deferred financing costs	**213**	61
Accretion of decommissioning obligation	**707**	704
Total	**$ 1,766**	$ 1,813

The decrease in our interest on bank debt for the first quarter, compared to the same quarter of 2013, resulted from lower average outstanding long-term debt and a lower average effective interest rate. Our average effective interest rate during the first quarter lowered to 3.9% from 5.2% in the same quarter of 2013. This decreased interest rate resulted from our election in the fourth quarter of 2013 to take the Bankers' Acceptances interest rates, which are currently lower than the previously elected Canadian prime rate, and adjustments to the applicable rate based on our improved Canadian EBITDA. As further discussed in the "Credit Facilities" section of this MD&A, we have the option to change the basis of our effective interest rate on our Canadian revolving credit facility.

Standby fees, included in finance charges and fees, increased during the first quarter compared to the same quarter of 2013, due to signing an international credit facility on March 15, 2013 which is also discussed under the "Credit Facilities" section of this MD&A. During 2013, we incurred $2.7 million of deferred financing costs associated with the signing of this facility and are amortizing these fees over this facility's anticipated remaining term, which currently is estimated at four years.

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

Three months ended March 31	2014	2013
($ thousands, except per unit amounts)		
Canada	**$ 12,287**	$ 13,768
Tunisia	**5,302**	4,201
Total	**$ 17,589**	$ 17,969
Per sales ($/boe)	**$ 19.95**	$ 19.95

DD&A expense during the first quarter, on an overall and boe basis, was comparable to the same quarter of 2013 as we reported similar overall sales volumes, with increased sales volumes in our Tunisian segment offset by decreases from Canada. The decrease in Canadian sales volumes resulted from our 2013 non-core property disposition program. In comparison, our first quarter 2013 Tunisian sales volumes were lower as we inventoried more crude oil volumes while waiting for a tanker to take delivery of that quarter's production. Depletion costs associated with inventoried Tunisian crude oil volumes are included in our inventory carrying amount and are reported as depletion in the quarter when the crude oil is sold.

Impairment of Development & Production Assets

At March 31, 2014 and 2013, we determined that there were no indications of impairment that would warrant an impairment test in any of our cash generating units. In addition, we determined that there were no sustained indicators that a recovery of prior periods' impairment was warranted at this time.

Gains on Disposition of Properties

There were no property dispositions during the first quarter. During the first quarter of 2013, we completed the sale of several petroleum and natural gas properties mostly located throughout Alberta, Canada for aggregate proceeds of $13.1 million, resulting in a gain of $6.3 million.

Income Tax Expense (Recovery)

Three months ended March 31	2014	2013
($ thousands)		
Current income tax expense	**$ 1,931**	$ 630
Deferred income tax recovery	**(226)**	(670)
Total	**$ 1,705**	$ (40)

The reported current income taxes are from our Adam Concession located onshore Tunisia. These taxes increased in the first quarter compared to the same quarter of 2013. This increase was due to higher crude oil revenues caused by higher sales volumes and pricing, resulting in higher taxable income.

We had deferred income tax recoveries of $0.2 million and $0.7 million for the first quarters of 2014 and 2013, respectively. The first quarter's recovery mostly resulted from an increase in the valuation of our international tax assets. We also had a decrease in the valuation allowance applied against our Canadian net–operating loss carry forwards. We were able to use some of these previous years' tax loss carry forwards to offset against the first quarter's Canadian segment's taxable income. We don't anticipate incurring Canadian corporate taxes given we had Canadian non-capital losses carried forward of $177.0 million at December 31, 2013. We have not reported deferred tax assets because it is not probable that we can utilize these assets against future taxable profit.

Net Income and Comprehensive Income

Three months ended March 31	2014	2013
($ thousands, except per share amounts)		
Net income	**$ 6,085**	$ 4,500
Per share - basic and diluted ($/share)	**0.03**	0.02
Comprehensive income	**$ 10,827**	$ 6,644
Per share - basic and diluted ($/share)	**0.05**	0.03
Weighted average shares outstanding (thousands)		
- basic	**214,188**	214,188
- diluted	**214,245**	214,188

Our net income of $6.1 million in the first quarter increased relative to the same quarter of 2013. This increase resulted from higher realized commodity pricing, an increase in crude oil sales volumes in both Canada and Tunisia, and lower exploration and evaluation expenses.

Comprehensive income, which includes our net income and foreign currency translation gains on our Tunisian operations, increased for the first quarter compared to the same quarter in 2013. This increase was consistent with the increase in net income plus a higher foreign currency translation gain on marking-to-market our Tunisian US dollar denominated net assets to the relatively weaker Canadian dollar.

Capital Resources, Capital Expenditures and Liquidity

We continue to focus on project economics, scale and repeatability from our core Canadian asset base to grow conventional liquids production and test resource play concepts. We are also continuing to review potential alternative strategies for our Tunisian operations in an attempt to better understand the valuation of these assets relative to the valuation being applied to our company.

Cash flow for the first quarter, cash on deposit and a decrease in our non-cash working capital financed the investment in capital, decommissioning, and exploration and evaluation expenditures.

Cash Flow

Three months ended March 31	2014	2013
($ thousands, except per share amounts)		
Cash flow from operations	**$ 8,601**	$ 3,892
Add back (deduct):		
Change in operating non-cash working capital	**19,243**	13,747
Deferred disposition proceeds	**-**	3,051
Decommissioning obligation expenditures	**605**	828
Cash flow(1)	**$ 28,449**	$ 21,518
Per share - basic and diluted(1)	**$ 0.13**	$ 0.10
Per sales ($/boe)(1)	**$ 32.27**	$ 23.90

(1) Cash flow, cash flow per share and cash flow per boe are non-IFRS measures. Cash flow is calculated from cash flow from continuing operations adjusted for changes in non-cash working capital, deferred disposition proceeds and decommissioning obligation expenditures. Cash flow per share or per boe is calculated from cash flow as previously defined divided by the weighted average basic and dilutive shares outstanding during the period or sales volumes, respectively. Management believes that cash flow is a key measure to assess our ability to finance capital expenditures and debt repayments. Cash flow 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 operating activities.

Cash flow for the first quarter increased by 32% to $28.5 million compared to the same quarter of 2013. This increase is partially due to higher Canadian and Tunisian crude oil sales and their higher netback, compared to the netback of an equivalent boe of natural gas. Stronger realized Canadian commodity pricing during the first quarter, compared to the same quarter of 2013, also contributed to both the higher netback and our reported increase in cash flow. The effect of higher Canadian commodity pricing and crude oil sale volumes on our accounts receivable as at March 31, 2014 was notable compared to December 31, 2013. This increase contributed to the reported change in operating non-cash working capital. The first quarter of 2013 included deferred disposition proceeds associated with the one-time termination of a potential partner's optional right to complete its earning and acquisition of an interest in our Cosmos Concession. If these deferred disposition proceeds had not been included in our 2013 our cash flow, our increase in the first quarter cash flow compared to the same quarter of 2013 would have been over 40%.

Credit Facilities

($ thousands)	March 31 2014	December 31 2013
Long-term debt	**$ 76,025**	$ 75,897
Less:		
Working capital excluding mark-to-market derivative contracts	**(1,635)**	(14,048)
Net debt[(1)]	**$ 74,390**	$ 61,849

(1) Net debt and working capital excluding mark-to-market derivate contracts are non-IFRS measures. Net debt is calculated as bank debt adjusted for working capital excluding mark-to-market derivative contracts. Working capital excluding mark-to-market derivative contracts is calculated as current assets less current liabilities both of which exclude derivative contracts and current liabilities excludes the current portion of debt. Management uses net debt 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, as management intends to hold each contract through to maturity of the contract's term as opposed to liquidating each contract's fair value or loss.

We did not draw on long-term debt during the first quarter, however, the reported carrying value increased as a result of the non-cash amortization of the deferred financing fees. As at March 31, 2014 and December 31, 2013, our drawn debt was $78.5 million. Our net debt of $74.4 million as at March 31, 2014, increased relative to our $61.8 million of net debt as at December 31, 2013 due to the first quarter's capital, exploration and decommissioning expenditures of $41.9 million exceeding our cash flow of $28.5 million combined with the foreign currency translation gain of $0.9 million on our US dollar held cash. We expected an increase in net debt during the first quarter resulting from our capital expenditures, associated mainly with our drilling campaigns, exceeding our cash flows.

At March 31, 2014 and December 31, 2013, our Canadian reserve-based 364 day revolving credit facility (the "Canadian Revolving Term Credit Facility"), which we hold with a syndicate of Canadian banks, had a maximum availability of $115.0 million. In June 2013, we extended the current revolving period to June 26, 2014 at which time this facility's revolving period and availability will be redetermined. In the event that the revolving period is not extended by the syndicate of banks on or prior to this date, all amounts then outstanding under the Canadian Revolving Term Credit Facility must be repaid before June 26, 2015. The Canadian Revolving Term Credit Facility is subject to a semi-annual review and redetermination. Changes in the availability of the Canadian 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 both March 31, 2014 and December 31, 2013, our drawings of $78.5 million and outstanding letters of credit of $0.4 million against the Canadian Revolving Term Credit Facility resulted in available credit on this facility of $36.1 million.

The Canadian Revolving Term Credit Facility is collateralized by floating charges and security interests over all present and future Canadian properties and other Canadian assets. Interest charged on amounts drawn on this facility vary based on the applicable pricing rate combined with the Bankers' Acceptances rates, which is the current interest rate option that we have selected. Other interest rate options that we can select are the Canadian prime rate, US Base rate and US LIBOR. The Canadian Revolving Term Credit Facility contains a covenant whereby the ratio of our 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. As at March 31, 2014, we were in compliance with this covenant and anticipate being in compliance through the existing term of this facility.

On March 15, 2013, we signed a US$75.0 million international amortizing reserve-based credit facility (the "International Credit Facility") for a term of five years with an international bank. Effective January 1, 2014, our available borrowing base on this facility was reduced to US$23.8 million (December 31, 2013 – US$46.5 million). This reduction was due to an increase in estimated future costs, as included in our December 31, 2013 reserve report for our Tunisian producing properties, over this facility's remaining four year term despite an increase in these reserves' estimated net recoverable values. At March 31, 2014 and December 31, 2013, we had no outstanding drawings against the International Credit Facility. The International Credit Facility's next semi-annual review is scheduled for June 2014 where the available amount will be reassessed and any outstanding draws must be paid down to the lower of the new available amount or the current repayment commitment. The term of the International Credit Facility can be reduced from the anticipated final maturity date in March 2018 to a date when the estimated reserve recoveries of the borrowing base assets fall below a prescribed rate.

The International Credit Facility is collateralized by floating charges and security interests over all of our Tunisian assets, including the shares of our international subsidiaries. Interest payable on drawings from the International Revolving Credit Facility will vary based on a prescribed margin plus US LIBOR.

Unamortized deferred financing costs of approximately $2.5 million remained at March 31, 2014 and will be amortized through to the anticipated expiry of each facility's agreement.

Capital Expenditures

Three months ended March 31				2014				2013
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 161**	**$ -**	**$ -**	**$ 161**	$ 2,533	$ -	$ -	$ 2,533
Drilling and completions	**18,443**	**15,727**	**-**	**34,170**	10,573	3,996	-	14,569
Facilities and equipment	**4,456**	**226**	**-**	**4,682**	3,781	2,812	-	6,593
Field expenditures	**23,060**	**15,953**	**-**	**39,013**	16,887	6,808	-	23,695
Capitalized G&A	**260**	**812**	**-**	**1,072**	295	1,026	-	1,321
Furniture and equipment	**-**	**-**	**306**	**306**	-	-	30	30
Total	**$ 23,320**	**$ 16,765**	**$ 306**	**$ 40,391**	$ 17,182	$ 7,834	$ 30	$ 25,046
Proceeds from dispositions	**$ -**	**$ -**	**$ -**	**$ -**	$ 13,060	$ -	$ -	$ 13,060

Wells Drilled

A summary of our drilling activities for the first quarter is as follows:

Three months ended March 31, 2014	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Oil	4.00	**3.44**	4.00	**3.26**	8.00	**6.70**
Gas	-	**-**	1.00	**0.37**	1.00	**0.37**
Development wells	4.00	**3.44**	5.00	**3.63**	9.00	**7.07**
Exploration gas well	-	**-**	1.00	**0.75**	1.00	**0.75**
Total	4.00	**3.44**	6.00	**4.38**	10.00	**7.82**

Canada Capital Expenditures

Our Canadian activity in the first quarter included an operated three (3.00 net) well Dunvegan drilling program at Albright. By the end of the quarter, two of these three drilled wells had been completed and brought on stream. At Karr, we drilled and completed one well (0.26 net) which should be brought on production in May 2014 and completed and brought on production a well (0.37 net) which was drilled in the fourth quarter of 2013. We also drilled and completed two (1.12 net) operated Montney wells during the first quarter, including an oil prospect at Gold Creek, Alberta and a liquids-rich natural gas prospect, that is currently under evaluation, at Birley/Umbach in northeastern British Columbia.

At Albright, we have now drilled ten (8.0 net) horizontal Dunvegan oil wells on the property since it was acquired in December 2012. These wells are currently producing an incremental 1,300 boepd (1,100 boepd net), at 79% oil, to the 280 boepd that comprised the original acquisition. For the remainder of 2014, we have budgeted at least two (2.0 net) additional wells at Albright, with up to 26 (22 net) locations identified.

At our non-operated Karr property, first quarter activity brought our total number of working interest wells in this area to ten (3.17 net). The operator has continued to reduce costs on the latest wells and every well has had initial production rates which met or exceeded our internal expectations. Current net production from this property is over 800 boepd (80% oil). There are two (0.63 net) more wells budgeted at Karr in 2014, with up to 19 (6.7 net) additional locations identified. Construction of a central oil battery (0.25 net) on the property is over half completed and should further improve well run times and reduce operating costs going forward.

Preliminary results of our Montney well at Gold Creek were encouraging, but predicting well performance will not be possible until we continue testing post-break-up. We own over 50 sections of Montney rights in this active Montney fairway, with numerous new wells being licensed and drilled by other operators. We have one more horizontal Montney well budgeted for 2014 in the Gold Creek area. We also own significant Montney acreage in the Elmworth (Alberta) and Knopcik (Alberta) areas, with other operators showing impressive well results and increased drilling activity immediately offsetting our land. We will continue to monitor these results and will likely propose our own activity in some or all of these areas starting in 2015.

Additional opportunities currently budgeted for 2014 include horizontal drilling locations in our Grande Prairie core area targeting Doe Creek oil, Dunvegan oil, Charlie Lake oil, Halfway oil, Doig oil, and Montney oil and/or natural gas. Preliminary well location surveys and licensing work required to increase the number of wells we could drill in 2014 on any of the various active plays is underway.

Tunisia Capital Expenditures

Our BBT Concession's capital activity in the first quarter of 2014 consisted of drilling four (3.44 net) wells and completing three (2.58 net) wells of our planned six (5.16 net) well program for 2014. Improved optimization of drilling and completions have brought the cost per vertical well down from the 2012 gross costs of $5.0 million to today's achieved cost of $4.0 million. These lower costs on vertical wells allow us to step further away from existing well control to improve our understanding of the reservoir structure and sand distribution across the 50km^2 field area which will in turn improve optimizing the future placement and orientation of the lateral sections of horizontal wells. We anticipate further cost savings on the drilling and completion costs of the remaining three wells of this six well campaign.

Drilling and completion activity at our BBT Concession for the first quarter consisted of:

- We finished drilling and completed the TT15 well (0.86 net), which had been spudded during the preceding quarter. We brought this well on production via natural flow in mid-February.
- The TT28 well (0.86 net) was drilled and completed with two intervals in the Ordovician Formation. After being put on production it flowed naturally for 20 days before loading up and being shut-in during the first quarter. During April, this well started naturally flowing prior to installation of a velocity string, which optimizes the flow rate, and a jet pump for artificial lifting.
- The TT18 well (0.86 net) was drilled and completed late in the first quarter and was brought on production via natural flow in mid-March.
- The TT19 well (0.86 net) was spudded in March with drilling and completions finished early in the second quarter of 2014. This well is now on production.

Although first quarter production volumes from this drilling activity was nominal, the combined initial test net production rate over 10 days of the three newly drilled and completed wells was approximately 470 bopd.

Civil construction was completed on the remaining two BBT locations, TT29 (0.86 net) and TT14 (0.86 net), of our planned six well program for 2014. This drilling program is anticipated to be completed in the second quarter of 2014. Also during the first quarter, the TT4 well (0.86 net) had a velocity string installed to optimize the well's flowing performance. This well's velocity string also increased the daily production rate and is expected to increase its recovery of our reserves. The TT7 well (0.86 net), which has been unable to flow on its own since the fourth quarter of 2013, had a jet pump installed, as already procured and taken from our TT20 wellsite, and was brought back on production in the first quarter.

The TT20 well (0.86 net) was drilled in the second quarter of 2013 and suspended pending a further evaluation. This well was tested for two weeks in the first quarter to evaluate its productivity. At the end of the two week test period this well was shut-in to further evaluate the production results of this test. In addition, after the successful injection test on our TT12 horizontal well (0.86 net) a work over was performed to change out the completion system with a coated completion better suited to long term water injection. Equipment was ordered for the surface injection facility and water injection from this facility is slated to start during the latter half of 2014. Based on performed simulation work, water injection into the TT12 horizontal well is expected to provide a significant increase in oil recoveries from the modelled area.

Final engineering of our BBT 13 kilometer gathering system, central gathering facility and oil battery is being completed and tendering packages were progressed during the first quarter. The materials for these facilities and equipment had previously been purchased and are on location and racked in the field.

The non-operated Adam Concession and BEK Permit had little expenditure activity during the first quarter. Planning is underway to drill one (0.05 net) development well on the Adam Concession and one (0.10 net) exploration well on the BEK permit. This drilling is planned to take place in the second half of 2014.

Decommissioning Obligation

At March 31, 2014, we had decommissioning obligations of $91.3 million (December 31, 2013 - $90.4 million) for the future abandonment and reclamation of our properties. This increase resulted primarily from additions related to our first quarter drilling program of $0.6 million and accretion charges of $0.7 million (same quarter of 2013 - $1.0 million and $0.7 million, respectively). The recognized accretion charges reflect the increase in the obligation associated with the passage of time. Offsetting this increase were abandonment and reclamation expenditures of $0.6 million (same quarter of 2013 - $2.4 million).

As at March 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. As at March 31, 2014 and December 31, 2013, a risk-free interest rate of up to 3.2% was used in order to calculate the present value of the obligation.

Outstanding Share Data

Authorized:

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

Details of share capital and options outstanding are as follows:

	March 31 2014	December 31 2013
Common shares outstanding	**214,187,681**	214,187,681
Share options	**13,328,449**	14,319,699
Weighted average common shares		
- basic	**214,187,681**	214,187,681
- diluted	**214,245,240**	214,187,681

As at May 12, 2014, we had 214,187,681 common shares and 13,600,323 share options outstanding.

Commodity Price Risk Management Contracts

To mitigate commodity price risk, we, with the approval of our Board of Directors, have entered into financial derivative contracts which assist us in better managing our future cash flows. This provides more certainty within determined commodities price ranges as to what we will receive on a portion of our crude oil and natural gas sales volumes. Our commodity price risk management activities are limited by adherence to a policy of our Board which determines which commodities may be subject to such contracts, the maximum contracted notional production volume, the referenced indexed price and the contractual terms.

Unsettled risk management contracts are recognized at their approximated fair value on the date of the condensed consolidated financial statements. Changes in the fair value of a risk management contract result from volatility in commodity prices and the remaining notional volumes through to the contract's term. Changes in the fair value between reporting periods are recognized in net income as unrealized risk management contract gains or losses. Realized risk management contract gains or losses are recognized in net income on unwinding of the financial derivative contract term. 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.

As at March 31, 2014, we had the following commodity price contracts with an estimated fair value current liability of $4.9 million:

Indexed Price	Notional Volumes	Company's Received Price	Remaining Contractual Term
AECO	5,000 GJ/d	$3.25/GJ to $3.50/GJ	April 1, 2014 to December 31, 2014
AECO	5,000 GJ/d	$3.68/GJ	April 1, 2014 to December 31, 2014
AECO	5,000 GJ/d	$3.5025/GJ	April 1, 2014 to October 31, 2014
WTI	500 bbl/d	$101.30/bbl	April 1, 2014 to December 31, 2014
Brent	500 bbl/d	$98.00 US/bbl to $108.00 US/bbl	April 1, 2014 to December 31, 2014

Based on guidance, these price risk contracts are expected to secure our received commodity prices on approximately 26% and 43% of sales volumes from crude oil and Canadian natural gas, respectively.

Outlook

As a result of increased commodity prices and the continued devaluation of the Canadian dollar, we are increasing our guidance for 2014 initially announced in our news release dated December 19, 2013.

	2014 Revised Guidance[1]			Original Guidance[2]		
($ millions, except boe/d)	Consolidated	International	Canada	Consolidated	International	Canada
Production (boe/d)	**9,600 - 10,380**	**1,850 - 2,130**	**7,750 - 8,250**	9,500 - 10,250	1,850 - 2,130	7,650 - 8,120
Cash flow	**$ 95 - $ 105**	**$ 40 - $ 45**	**$ 55 - $ 60**	$ 82 - $ 90	$ 42 - $ 46	$ 40 - $ 44
Capital expenditures	**$ 95 - $ 105**	**$ 35 - $ 40**	**$ 60 - $ 65**	$ 85	$ 36	$ 49
Net debt	**$ 65 - $ 70**	**-**	**$ 65 - $ 70**	$ 60	-	$ 60
Maximum available credit	**$ 139**	**US $ 23.8**	**$ 115**	$ 139	US $ 23.8	$ 115

(1) Pricing assumptions: Canadian crude oil - $95.97/bbl, Canadian natural gas - $4.98/mcf; Tunisian crude oil - $115.64/bbl, Tunisian natural gas - $13.78/mcf; FX-USD $1 = CND $0.93
(2) Pricing assumptions: Canadian crude oil - $87.89/bbl, Canadian natural gas - $3.29/mcf; Tunisian crude oil - $103.47/bbl, Tunisian natural gas - $12.48/mcf; FX-USD $1 = CND $0.97

We are encouraged by our results to date in 2014 and look forward to the balance of the year. Our optimism stems from our focused development at Karr, Albright and the BBT Concession which continues to deliver meaningful cash flow growth and the encouraging preliminary results at our first Gold Creek Montney well and the future activity that may result from this well. Our evaluation of the Birley/Umbach well will be complete in the second quarter. In light of the recent strengthening of natural gas prices, we are revisiting our inventory of natural gas projects that now exceed our minimum threshold for investment.

As previously announced, we continue to review potential alternative strategies for our international business in an attempt to better understand the respective valuation of our domestic and international assets and to identify potential alternatives that may improve our market valuation as a hybrid company relative to our domestic peers. We caution that there is no assurance or guarantee that such review will result in a transaction or, if a transaction is undertaken, the terms or timing of such transaction.

Quarterly Information

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

	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	Jun. 30 2013	Mar. 31 2013	Dec. 31 2012	Sept. 30 2012	Jun. 30 2012
OPERATIONS								
Production								
Oil *(bbl/d)*	**3,672**	3,356	3,456	3,298	3,565	4,035	3,516	3,195
Natural gas liquids *(bbl/d)*	**950**	722	753	874	1,005	1,003	1,141	1,122
Natural gas *(mcf/d)*	**30,839**	33,612	35,820	34,458	37,736	39,585	43,839	43,387
Average daily production *(boe/d)*	**9,761**	9,680	10,180	9,916	10,860	11,636	11,964	11,548
Sales								
Oil *(bbl/d)*	**3,707**	3,725	3,558	3,588	2,710	4,264	3,929	2,385
Natural gas liquids *(bbl/d)*	**950**	722	753	874	1,005	1,003	1,141	1,122
Natural gas *(mcf/d)*	**30,839**	33,612	35,820	34,458	37,736	39,584	43,839	43,387
Average daily sales *(boe/d)*	**9,797**	10,049	10,282	10,205	10,006	11,865	12,377	10,738
Sales Prices								
Average oil price *($/bbl)*	**$ 105.83**	$ 98.57	$ 104.46	$ 98.07	$ 95.03	$ 97.72	$ 95.61	$ 89.11
Average natural gas liquids price *($/bbl)*	**$ 74.10**	$ 63.74	$ 62.36	$ 55.06	$ 58.85	$ 57.71	$ 56.42	$ 55.46
Average natural gas price *($/mcf)*	**$ 6.42**	$ 3.99	$ 3.00	$ 4.13	$ 3.72	$ 3.39	$ 2.57	$ 2.08
Netback(1)								
Average commodity pricing *($/boe)*	**$ 67.44**	$ 54.46	$ 51.17	$ 53.13	$ 45.70	$ 51.30	$ 44.67	$ 33.97
Royalties *($/boe)*	**$ (5.57)**	$ (4.61)	$ (3.30)	$ (4.88)	$ (3.79)	$ (0.64)	$ (2.50)	$ (3.29)
Net production expenses *($/boe)*(1)	**$ (19.44)**	$ (19.32)	$ (19.28)	$ (17.31)	$ (16.52)	$ (18.98)	$ (18.38)	$ (14.46)
Cash G&A *($/boe)*(1)	**$ (5.91)**	$ (3.10)	$ (2.46)	$ (3.02)	$ (2.83)	$ (4.48)	$ (2.54)	$ (3.74)
Netback *($/boe)*(1)	**$ 36.52**	$ 27.43	$ 26.13	$ 27.92	$ 22.56	$ 27.20	$ 21.25	$ 12.48
Wells Drilled (net)								
Oil	**6.70**	1.65	3.86	1.77	3.61	2.96	1.11	0.86
Gas	**1.12**	-	-	-	-	-	-	-
Dry	**-**	-	-	0.86	-	-	-	0.86
Total wells drilled *(net)*	**7.82**	1.65	3.86	2.63	3.61	2.96	1.11	1.72
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties(2)	**$ 54,545**	$ 46,088	$ 45,285	$ 44,805	$ 37,740	$ 55,303	$ 48,012	$ 29,979
Cash flow(1)(2)	**$ 28,449**	$ 20,179	$ 23,146	$ 22,179	$ 21,518	$ 28,757	$ 20,935	$ 9,830
Per share - basic and diluted *($/share)*	**$ 0.13**	$ 0.09	$ 0.11	$ 0.10	$ 0.10	$ 0.13	$ 0.10	$ 0.05
Net income (loss)(2)(3)	**$ 6,085**	$ (39,002)	$ 3,812	$ 3,990	$ 4,500	$ (36,708)	$ (12,417)	$ (24,812)
Per share - basic and diluted *($/share)*	**$ 0.03**	$ (0.18)	$ 0.02	$ 0.02	$ 0.02	$ (0.17)	$ (0.06)	$ (0.12)
Capital expenditures	**$ 40,391**	$ 14,162	$ 20,961	$ 23,059	$ 25,046	$ 50,456	$ 22,674	$ 13,083
Net debt(1)	**$ 74,390**	$ 61,849	$ 65,105	$ 66,340	$ 64,440	$ 72,383	$ 80,428	$ 77,092
Total assets	**$ 604,419**	$ 555,341	$ 593,192	$ 621,143	$ 617,459	$ 622,476	$ 628,542	$ 637,238
Common Shares *(thousands)*								
Weighted average during period - basic	**214,188**	214,188	214,188	214,188	214,188	214,188	214,188	214,188
Weighted average during period - diluted	**214,245**	214,188	214,188	214,188	214,188	214,188	214,188	214,188
Outstanding at period end	**214,188**	214,188	214,188	214,188	214,188	214,188	214,188	214,188

(1) Cash flow, cash flow per share, net debt, netback, net production expense and cash G&A 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) Significant Tunisian crude oil production of 77,000 barrels and 88,000 barrels was not sold at September 30, 2012 and March 31, 2013, respectively.

(3) Includes $26.5 million and $55.5 million in impairment charges against Canadian properties for the three months ended June 30, 2012 and December 31, 2012, respectively and $35.5 million in impairment charges against Canadian and Tunisian properties for the three months ended December 31, 2013.

Factors That Have Caused Variations over the Quarters

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

Generally, our Canadian non-core property disposition program, which commenced in 2011 and continued through 2013, resulted in a lower trend of Canadian production volumes, especially natural gas and natural gas liquids. This effect was partially offset by increased Tunisian crude oil production from our BBT Concession from the fourth quarter of 2011 until the third quarter of 2013, at which time our drilling program was delayed, and increased Canadian crude oil production resulting from the partial reinvestment of our disposition proceeds into core area crude oil properties. When combined with the effect of the Brent, Edmonton par and AECO benchmarks, which have generally trended up since the second quarter of 2012, petroleum and natural gas revenues, net of royalties, have recovered from the effects of the non-core property disposition program. This, in turn, when combined with an increased proportion of produced crude oil, and this commodity's higher associated netback, relative to the total volumes, generated sufficient cash flow to generally reduce our net debt throughout 2012 and 2013. This has allowed us to avoid having to access the equity markets. Our active drilling programs, described below, resulted in a temporary increase in our first quarter net debt, despite not drawing on our credit facilities.

Of particular note, as a result of an increase in the relatively higher priced/higher netback Tunisian crude oil production that remained unsold at the end of the first quarter of 2013 and the second quarter of 2012, the average commodity sales price, petroleum and natural gas revenues, cash flow and netback per boe declined for these quarters. Further, for the second and fourth quarters of 2012, $26.5 million and $55.5 million, respectively, of impairment charges were reported against our Canadian CGUs, while in the fourth quarter of 2013, $32.0 million and $3.5 million of impairment charges were reported against our offshore, non-producing Tunisian CGU and a Canadian CGU, respectively, resulting in significantly higher net losses during these quarters, in comparison to the other quarters. Comprehensive income essentially trends with net income (loss) but can differ should there be a change in the value of the Canadian dollar relative to the US dollar, the functional currency of our Tunisian operations. Capital expenditures have generally focused on our Tunisian organic growth, however; since the third quarter of 2013 capital expenditures related to our Canadian drilling and completions programs increased as we pursued oil opportunities in our core areas. We saw a reduction in our Tunisian capital expenditures in the third and fourth quarter of 2013 as we were awaiting the additional governmental approvals that were granted at the end of the fourth quarter of 2013 and led to an increase in Tunisian capital expenditures during the first quarter of 2014.

Please refer to "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, 2013 ("AIF") and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out in our AIF are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally. If any of the these risks or other risks occur, our business, prospects, financial condition, results of operations and cash flows could be adversely affected in a material way.

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

New Accounting Amendments and Interpretation

We adopted the following new accounting amendments and interpretation which are effective for the interim condensed consolidated financial statements and the annual consolidated financial statements commencing January 1, 2014:

- Amendments to IAS 32, *Financial Instruments: Presentation*, 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 condensed consolidated financial statements as at March 31, 2014 and December 31, 2013.

Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Controller, who is temporarily acting in the capacity of Chief Financial Officer ("Interim 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 Interim CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

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

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 about us, including management's assessment of our future plans and operations, certain statements in this MD&A are "forward-looking statements". In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this MD&A speak only as of the date of this document and are expressly qualified by this cautionary statement.

In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: that we will be better able to manage our operating cost structure going forward; the anticipated timing that the central gathering facility and oil battery on the BBT Concession is expected to be operational and the anticipated improvement in well run times and reduced operating costs as a result thereof; wells budgeted for the remainder of the year; the anticipated increase in oil recoveries resulting from the conversion of the BBT TT12 well to a water injection well and the timing thereof; the anticipated improved well run times and reduced operating costs resulting from the construction of a central battery at our Karr property; anticipated further cost savings on the drilling and completion costs of the remaining three wells of our six well program at BBT; the volume and product mix of our oil and natural gas production on certain newly drilled wells, and the anticipated production volumes therefrom; anticipated operational and cost efficiencies; operations to be conducted, wells to be drilled and/or completed and the timing thereof on certain of our Canadian and Tunisian properties and, in certain cases, the expected increase in production volumes resulting therefrom; future results from operations and operating metrics; and future development, exploration, acquisition and development activities (including drilling plans) and the timing thereof and related production expectations; expected future cash G&A per boe; as well as management's future expectations regarding production, cash flow, capital expenditures, net debt and maximum available credit set out 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, our ability to continue to operate in Tunisia with limited logistical, security and operational issues, future capital expenditure levels, future oil and natural gas prices, future oil and natural gas production levels, our ability to obtain equipment in a timely manner to carry out development activities, our lenders reviewing our credit facilities in the time periods currently scheduled; the impact of increasing competition, our ability to add production and reserves through exploration and development activities, all costs in respect of certain wells being accurately estimated, certain commodity price and other cost assumptions, the continued availability of adequate debt financing 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, political and security risks associated with our Tunisian operations, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve and resource estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, unexpected 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, inability to access sufficient capital from internal and external sources and unanticipated increased or unforeseen costs. 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 our annual information form for the year ended December 31, 2013 and other documents on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Barrels of Oil Equivalent

Barrels of oil equivalent (boe) is calculated using the conversion factor of 6 mcf (thousand cubic feet) of natural gas being equivalent to one barrel of oil. Boe 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.