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Management's Discussion and Analysis

Chinook Energy Inc.

Chinook Energy Inc. | 700, 700 - 2nd Street SW Calgary, Alberta T2P 2W1 TSX:CKE

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. ("our", "we" or "us") for the three and nine months ended September 30, 2013 and 2012 and should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes as at and for the three and nine months ended September 30, 2013 and 2012 and the consolidated financial statements and accompanying notes as at and for the years ended December 31, 2012 and 2011. This MD&A is based on information available as at November 14, 2013.

The terms "third quarter" and "year to date" or similar terms are used throughout this document and refer to the three and nine months ended September 30, 2013, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three and nine month periods ended September 30, 2013. The term "same period of 2012" or similar terms are used throughout this document and refer to the three or nine month periods ended September 30, 2012 depending on the 2013 period under discussion.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2012 ("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 and nine months ended September 30, 2013 and 2012 have been prepared in accordance with IAS 34 'Interim Financial Reporting' using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board. The consolidated financial position and results of operations 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 share amounts or as otherwise noted. Certain financial measures referred to in this MD&A, such as cash flow, cash flow per share, corporate netbacks, 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 public oil and natural gas exploration and development company with predominately natural gas and liquids reserves in western Canada and crude oil reserves onshore and offshore 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 ("TSX") under the symbol "CKE". Our head office and principal address is Suite 700, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

Our continuing operating and reportable segments are as follows:

- **Canada** – includes our Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in the Peace River and Grande Prairie areas located along the northern portion of the border of the provinces of British Columbia and Alberta.
- **Tunisia** – includes eight blocks totaling three million gross acres offshore in the Gulf of Hammamet within the Pelagian Basin (Cosmos, Yasmin and Hammamet Offshore) and the Sud Remada, Bir Ben Tartar, Jenein, Adam and Borj El Khadra Blocks, all onshore properties located within the Ghadames Basin. Our producing properties are Bir Ben Tartar and Adam.
- **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 September 30		Nine months ended September 30	
	2013	2012	2013	2012
OPERATIONS				
Production				
Oil *(bbl/d)*	**3,456**	3,516	**3,439**	3,510
Natural gas liquids *(bbl/d)*	**753**	1,141	**877**	1,155
Natural gas *(mcf/d)*	**35,820**	43,839	**35,998**	46,215
Average daily production *(boe/d)*	**10,180**	11,964	**10,316**	12,367
Sales				
Oil *(bbl/d)*	**3,558**	3,929	**3,288**	3,388
Natural gas liquids *(bbl/d)*	**753**	1,141	**877**	1,155
Natural gas *(mcf/d)*	**35,820**	43,839	**35,998**	46,215
Average daily sales *(boe/d)*	**10,282**	12,377	**10,165**	12,245
Sales Prices				
Average oil price *($/bbl)*	**$ 104.46**	$ 95.61	**$ 99.57**	$ 96.15
Average natural gas liquids price *($/bbl)*	**$ 62.36**	$ 56.42	**$ 58.61**	$ 61.03
Average natural gas price *($/mcf)*	**$ 3.00**	$ 2.57	**$ 3.61**	$ 2.31
Corporate Netbacks(1)				
Average commodity pricing *($/boe)*	**$ 51.17**	$ 44.67	**$ 50.05**	$ 41.07
Royalties *($/boe)*	**$ (3.30)**	$ (2.50)	**$ (3.98)**	$ (3.37)
Net production expenses *($/boe)*(1)	**$ (19.28)**	$ (18.38)	**$ (17.73)**	$ (16.97)
Cash G&A *($/boe)*(1)	**$ (2.46)**	$ (2.54)	**$ (2.77)**	$ (3.07)
Corporate netbacks *($/boe)*(1)	**$ 26.13**	$ 21.25	**$ 25.57**	$ 17.66
Wells Drilled *(net)*				
Oil	**3.86**	1.11	**9.24**	5.13
Gas	**-**	-	**-**	1.00
Dry	**-**	-	**0.86**	0.96
Total wells drilled *(net)*	**3.86**	1.11	**10.10**	7.09
FINANCIAL *($ thousands, except per share amounts)*				
Petroleum & natural gas revenues, net of royalties	**$ 45,285**	$ 48,012	**$ 127,830**	$ 126,500
Cash flow(1)	**$ 23,146**	$ 20,935	**$ 66,843**	$ 49,939
Per share - basic and diluted *($/share)*	**$ 0.11**	$ 0.10	**$ 0.31**	$ 0.23
Net income (loss)	**$ 3,812**	$ (12,417)	**$ 12,302**	$ (54,320)
Per share - basic and diluted *($/share)*	**$ 0.02**	$ (0.06)	**$ 0.06**	$ (0.25)
Capital expenditures	**$ 20,961**	$ 22,674	**$ 69,066**	$ 59,203
Net debt(1)	**$ 65,105**	$ 80,428	**$ 65,105**	$ 80,428
Total assets	**$ 593,192**	$ 628,542	**$ 593,192**	$ 628,542
Common Shares *(thousands)*				
Weighted average during period				
- basic and diluted	**214,188**	214,188	**214,188**	214,188
Outstanding at period end	**214,188**	214,188	**214,188**	214,188

(1) Cash flow, net debt, corporate 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 September 30				2013				2012
	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	**1,853**	**753**	**34,563**	**8,367**	1,567	1,141	42,646	9,816
Tunisia	**1,603**	**-**	**1,257**	**1,813**	1,949	-	1,193	2,148
Total(1)	**3,456**	**753**	**35,820**	**10,180**	3,516	1,141	43,839	11,964
Sales								
Canada	**1,853**	**753**	**34,563**	**8,367**	1,567	1,141	42,646	9,816
Tunisia	**1,705**	**-**	**1,257**	**1,915**	2,362	-	1,193	2,561
Total(1)	**3,558**	**753**	**35,820**	**10,282**	3,929	1,141	43,839	12,377

Nine months ended September 30				2013				2012
	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	**1,670**	**877**	**34,746**	**8,338**	1,882	1,155	45,182	10,567
Tunisia	**1,769**	**-**	**1,252**	**1,978**	1,628	-	1,033	1,800
Total(1)	**3,439**	**877**	**35,998**	**10,316**	3,510	1,155	46,215	12,367
Sales								
Canada	**1,670**	**877**	**34,746**	**8,338**	1,882	1,155	45,182	10,567
Tunisia	**1,618**	**-**	**1,252**	**1,827**	1,506	-	1,033	1,678
Total(1)	**3,288**	**877**	**35,998**	**10,165**	3,388	1,155	46,215	12,245

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

Our predominately crude oil Tunisian production volumes of 1,978 boe per day for the year to date, increased by 10% relative to the same period of 2012. The year to date crude oil production increase was substantially from our Ordovician oil discovery located on the Bir Ben Tartar Concession ("BBT"). During the third quarter we finished drilling and completed the TT20 well (0.86 net). We are currently awaiting further testing of this well following the recent installation of a jet pump. We also completed and began production from our TT21 well (0.86 net) during the third quarter, bringing our operated development 2013 well count to three (2.58 net) of our planned five (4.30 net) well program. The current year to date Tunisian production volume increase also resulted from our BBT TT10, TT11, and TT12 horizontal wells which began producing either during the first half of 2013 or the fourth quarter of 2012 (2.58 net wells). These wells increased our average year to date production by approximately 300 barrels of oil per day relative to the same period in 2012, as partially offset by natural production declines, shut-ins to assess increased water cuts, a completion operation to assess a lower non-productive interval and workovers. The Tunisian production volumes of 1,813 boe per day for the third quarter were a decrease of 16% relative to the same period of 2012. We were informed by the Tunisian Regulatory Authority that a new application and approval process would be required by the Agence Nationale de Protection de l'Environnement ("ANPE") prior to the receipt of approvals for more well locations on our BBT Concession. This new application 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 submitted on October 21, 2013. We expect a response to our application in December 2013. This application delay will cause us to postpone one planned 2013 well into early 2014. The increased Tunisian natural gas sales volumes for the current reporting periods, as compared to the same periods in 2012, were from our onshore Adam Concession and resulted from an increase in sales pipeline capacity allowing previously flared natural gas to be sold.

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 after first being transported and stored at a terminal facility at the Port of La Skhira. The portion of crude oil production remaining stored in our tanks at each reporting date is reported as inventory.

Canadian crude oil production increased during the current quarter to its highest level since the first quarter of 2012, due to production from our drilling program on certain acquired properties in the Grande Prairie area. Our natural gas production was lifted by placing back onto production certain dry natural gas properties, which were previously shut-in, because of the recent improvement in natural gas pricing. Even though our production during the current quarter was an increase over the second quarter of 2013, overall production levels of our Canadian segment decreased approximately 1,400 and 2,200 boe per day for the current reporting periods, respectively, as compared to the same periods of 2012. These decreases include approximately 1,100 and 2,100 boe per day of lost production during the current reporting periods, associated with non-core property dispositions made during 2012 and 2013, in addition to natural reservoir production declines and non-operated and third party facility downtime.

Drilling and completion expenditures for the third quarter totalled $14.8 million (same quarter of 2012 - $19.7 million), which included our Tunisian segment's drilling and completion expenditures of $8.1 million (same quarter of 2012 - $17.1 million). Third quarter Tunisian activity included finishing drilling and completion of the TT20 well (0.86 net) for $3.2 million net, the completion and equipping of our TT21 well (0.86 net) and the completion of a side track on our non-operated Karma-2 well (0.05 net) located on our producing onshore Adam Concession.

We continue to monitor costs, drilling efficiencies and well performance and adjust our near term BBT development plans accordingly. Vertical well costs have improved materially due to substantial well cost reductions resulting from improved optimization of drilling and completions from over $5.0 million, on a gross basis in 2012 to $4.0 million today, as achieved in the drilling and completion of our TT20 well, with a projected future cost of $3.5 million. These lower costs on vertical wells allows 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.

The iterative process we are experiencing is not unusual in the early stages of a new play such as the one at BBT. The horizontal wells have exceeded our base expectations from a volume perspective, but have introduced the issue of water production which we did not encounter with the vertical wells. Water cuts remain stable and three of our four horizontal wells that have enough history to develop a trend, are at or above our base case type curve. We are working to improve the horizontal well economics with both an improved understanding of the reservoir (fracture and well orientation) and with operational efficiencies (well design and water shut offs) and expect a mix of horizontal and vertical wells to be drilled as we continue to appraise and develop the reservoir.

As well, we have been installing jet pump systems 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 a service rig to run the pump. Although we are encouraged by the early results, for future applications we are working to improve the logistics, costs around availability and uptime of these jet pump systems.

Our Canadian segment's drilling and completion expenditures for the third quarter were $6.7 million (comparable quarter of 2012 - $2.6 million) and included costs associated with the drilling and completion of a three (3.0 net) well program on our Albright and Beaverlodge properties which began in the second quarter of 2013. In addition, our partner began drilling the first well of a four well (1.2 net) drilling program at our Karr property.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended September 30			2013			2012
($ thousands, except per unit amounts)	Canada	Tunisia	Total(1)	Canada	Tunisia	Total(1)
Oil sales	**$ 16,626**	**$ 17,564**	**$ 34,190**	$ 11,565	$ 22,993	$ 34,558
$/bbl	**97.53**	**111.98**	**104.46**	80.23	105.82	95.61
Natural gas liquids sales	**$ 4,323**	**$ -**	**$ 4,323**	$ 5,924	$ -	$ 5,924
$/bbl	**62.36**	**-**	**62.36**	56.42	-	56.42
Natural gas sales	**$ 8,116**	**$ 1,776**	**$ 9,892**	$ 8,706	$ 1,668	$ 10,374
$/mcf	**2.55**	**15.36**	**3.00**	2.22	15.20	2.57
Petroleum and natural gas revenue	**$ 29,065**	**$ 19,340**	**$ 48,405**	$ 26,195	$ 24,661	$ 50,856
$/boe	**37.76**	**109.81**	**51.17**	29.01	104.68	44.67

Nine months ended September 30			2013			2012
($ thousands, except per unit amounts)	Canada	Tunisia	Total(1)	Canada	Tunisia	Total(1)
Oil sales	**$ 41,659**	**$ 47,730**	**$ 89,389**	$ 43,086	$ 46,183	$ 89,269
$/bbl	**91.35**	**108.06**	**99.57**	83.54	111.91	96.15
Natural gas liquids sales	**$ 14,026**	**$ -**	**$ 14,026**	$ 19,313	$ -	$ 19,313
$/bbl	**58.61**	**-**	**58.61**	61.03	-	61.03
Natural gas sales	**$ 30,400**	**$ 5,085**	**$ 35,485**	$ 24,697	$ 4,515	$ 29,212
$/mcf	**3.20**	**14.87**	**3.61**	1.99	15.96	2.31
Petroleum and natural gas revenue	**$ 86,085**	**$ 52,815**	**$138,900**	$ 87,096	$ 50,698	$ 137,794
$/boe	**37.82**	**105.91**	**50.05**	30.08	110.25	41.07

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

Petroleum and natural gas revenues of $48.4 million and $138.9 million during the current reporting periods were relatively consistent with the same periods of 2012 as increased average commodity pricing offset decreased average sales volumes.

Canadian Petroleum and Natural Gas Revenue and Prices

Our Canadian petroleum and natural gas revenue increased during the third quarter and was consistent during the year to date period relative to the same periods of 2012. During the third quarter the increased petroleum and natural gas pricing as well as higher crude oil sales, more than offset lower natural gas and natural gas liquids sales volumes. For the year to date, higher crude oil and natural gas pricing was offset by lower sales volumes. All Canadian pricing benchmarks increased in the current reporting periods as compared to the same periods in 2012, but contributing to the increase in the average petroleum and natural gas pricing was an increase in the weighted average of crude oil sales volumes within the Canadian segment to 22% and 20% of total production, respectively. This increase is the result of our focus on development of our "oily" Canadian properties in addition to the change in our commodity production portfolio resulting from both "oily" acquisitions and dry natural gas weighted dispositions.

Tunisian Petroleum and Natural Gas Revenue and Prices

Our Tunisian petroleum and natural gas revenue for the year to date increased as compared to the same period of 2012 due to higher sales volumes from our BBT Concession, as partially offset by lower petroleum and natural gas pricing. For the third quarter, our Tunisian petroleum and natural gas revenue decreased relative to the same period of 2012 as the higher petroleum and natural gas pricing was more than offset by lower sales volumes from our BBT Concession.

Benchmark Prices

	Three months ended September 30		Nine months ended September 30	
	2013	2012	**2013**	2012
Oil				
Edmonton par *($/bbl)*	**$ 104.74**	$ 84.39	**$ 95.18**	$ 86.91
Brent *($US/bbl)*	**$ 109.71**	$ 109.95	**$ 108.24**	$ 112.46
Natural gas liquids				
WTI[1] *($US/bbl)*	**$ 105.83**	$ 92.22	**$ 98.14**	$ 96.20
Natural gas				
AECO *($/mcf)*	**$ 2.47**	$ 2.31	**$ 3.10**	$ 2.14

(1) West Texas Intermediate

Crude Oil Pricing

Our respective average crude oil sales realized price for the current periods of $104.46 and $99.57 per barrel increased from $95.61 and $96.15 per barrel during the same periods in 2012.

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 current reporting periods, as did our average realized Canadian crude oil price, as compared to the same periods in 2012.

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 Tunisian crude oil price decreased during the year to date, as compared to the same period of 2012.

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. 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 year to date realized natural gas liquid price decreased to 62% from 70% in the same period of 2012 as a surge in liquids-rich natural gas drilling industry activity significantly increased the supply. When combined with the partially offsetting higher Edmonton par benchmark, our year to date realized natural gas liquids price of $58.61 per barrel decreased by four percent relative to the same period of 2012.

Natural Gas Pricing

Our Canadian realized natural gas price of $2.55 and $3.20 per mcf for the third quarter and year to date 2013, respectively, showed significant improvement from the $2.22 and $1.99 per mcf reported for the same periods of 2012. 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 September 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 2,718**	**$ 402**	**$ 3,120**	$ 2,149	$ 695	$ 2,844
Per sales *($/boe)*	**$ 3.53**	**$ 2.28**	**$ 3.30**	$ 2.38	$ 2.95	$ 2.50
Percent of Revenues *(%)*	**9**	**2**	**6**	8	3	6

Nine months ended September 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 9,707**	**$ 1,363**	**$ 11,070**	$ 9,838	$ 1,456	$ 11,294
Per sales *($/boe)*	**$ 4.27**	**$ 2.74**	**$ 3.98**	$ 3.40	$ 3.17	$ 3.37
Percent of Revenues *(%)*	**11**	**3**	**8**	11	3	8

For the third quarter, our royalties of $3.1 million increased slightly relative to the same quarter of 2012. This increase resulted from higher Canadian crude oil revenues due to improved pricing and sales volumes. Because of higher Canadian petroleum and natural gas pricing, the Canadian royalties on a boe basis also increased while royalties as a percentage of revenues remained relatively unchanged. The decrease in Tunisian royalties resulted from lower Tunisian sales from our royalty paying Adam Concession. A smaller proportion of our Tunisian crude oil sales from this Concession resulted in lower royalty costs on a boe basis, despite higher crude oil pricing as we are presently paying an average royalty rate of 9% for natural gas and 12% for crude oil on our Adam Concession's sales volumes. We do not pay royalties on our Tunisian BBT Concession's sales volume which is governed by a profit sharing contract between ourselves and ETAP.

For the year to date, our royalties of $11.1 million were relatively consistent with the same period of 2012. Higher Canadian crude oil and natural gas pricing were offset by lower sales volumes resulting in consistent royalties, including as a percentage of revenue, while this higher pricing increased the Canadian royalty costs on a boe basis. Lower Tunisian crude oil and natural gas pricing as well as a decrease in the proportion of Tunisian crude oil sales from our Adam Concession, resulted in lower Tunisian royalty costs per boe.

Production and Operating Expense

Three months ended September 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating expense	**$ 13,972**	**$ 5,597**	**$ 19,569**	$ 15,788	$ 5,561	$ 21,349
Less:						
Processing & gathering revenues	**(1,330)**	**-**	**(1,330)**	(419)	-	(419)
Net production & operating expense[(1)]	**$ 12,642**	**$ 5,597**	**$ 18,239**	$ 15,369	$ 5,561	$ 20,930
Per sales net production & operating expenses *($/boe)*[(1)]	**$ 16.42**	**$ 31.78**	**$ 19.28**	$ 17.02	$ 23.61	$ 18.38
Per sales production & operating expenses *($/boe)*	**$ 18.15**	**$ 31.78**	**$ 20.69**	$ 17.48	$ 23.61	$ 18.75

Nine months ended September 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating expense	**$ 41,647**	**$ 13,581**	**$ 55,228**	$ 51,066	$ 11,103	$ 62,169
Less:						
Processing & gathering revenues	**(6,037)**	**-**	**(6,037)**	(5,229)	-	(5,229)
Net production & operating expense[(1)]	**$ 35,610**	**$ 13,581**	**$ 49,191**	$ 45,837	$ 11,103	$ 56,940
Per sales net production & operating expenses *($/boe)*[(1)]	**$ 15.64**	**$ 27.23**	**$ 17.73**	$ 15.83	$ 24.14	$ 16.97
Per sales production & operating expenses *($/boe)*	**$ 18.29**	**$ 27.23**	**$ 19.90**	$ 17.63	$ 24.14	$ 18.53

(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 income. 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.

Consistent with a decrease in sales volumes during the third quarter and year to date, the production and operating expense of $19.6 million and $55.2 million, respectively, decreased relative to the same periods of 2012.

In Canada, the $14.0 million and $41.6 million of production and operating expense for the third quarter and year to date decreased, respectively, relative to the same periods of 2012. These decreases resulted primarily from lower sales volumes due to Canadian property dispositions during 2012 and 2013. The increased Canadian crude oil sales volumes weighting within this segment has put increased cost pressure on our Canadian production costs per boe as the cost of production of crude oil is generally higher than that of natural gas. However, the price premium on crude oil has resulted in increased Canadian average realized commodity pricing which in turn has contributed to higher Canadian netbacks, despite increased production costs per boe, in the current reporting periods as compared to the same periods in 2012. We continue to focus on improving our Canadian operating cost structure which has resulted in various process changes and cost saving initiatives.

In Tunisia, the effect on our operating costs from the decrease in sales volumes, in the third quarter, was offset by increased costs for equipment rentals, water hauling, water disposal and a workover on our TT12 well, in addition to the strengthening US dollar, compared to the same quarter in 2012. In addition to these increased costs, the increase in the proportion of sales from our higher operating cost BBT Concession during the current reporting periods resulted in an increase in our operating costs per boe as compared to the same periods of 2012. Finally, for the year to date, as compared to the same period in 2012, the higher Tunisian operating costs resulted from increases in sales volumes in addition to the aforementioned higher production costs per boe.

We expect Tunisian BBT operating costs per boe to decrease by 25 to 30 percent as anticipated to take effect in 2014 as production volumes increase and the planned early production facility comes on stream, which in turn will lower our existing equipment rental and water hauling expenses, in addition to lower oil trucking costs.

Our Tunisian operating costs associated with the inventoried crude oil as at September 30, 2013, are not reported on the condensed consolidated statement of operations but rather are included as a component of the inventory's carrying amount on an equivalent production cost per boe. These inventoried costs will be reported in the fourth quarter of 2013 when we sell the associated crude oil volumes.

General & Administrative ("G&A") Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2013**	2012	**2013**	2012
G&A expense	**$ 3,138**	$ 3,502	**$ 8,688**	$ 12,103
Add back/(deduct):				
Share-based compensation	**(370)**	(878)	**(1,095)**	(2,589)
Provision for bad debts	**(704)**	-	**(704)**	-
Amortization of deferred lease liability	**264**	264	**792**	792
Cash G&A expense(1)	**$ 2,328**	$ 2,888	**$ 7,681**	$ 10,306
Per sales *($/boe)*	**$ 2.46**	$ 2.54	**$ 2.77**	$ 3.07

(1) Cash G&A is a non-IFRS measure and is calculated as G&A less share-based compensation 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 third quarter and year to date decreased as compared to the same periods of 2012. This was due to lower staffing and share-based compensation expenses. Lower staffing costs resulted from our decision in November 2012 to reduce Canadian office staffing levels in conjunction with the 2011 and 2012 Canadian non-core property disposition program. Lower share-based compensation costs resulted from an increase in recoveries on forfeited unvested options and less fair value remaining to expense on unvested outstanding options.

Corporate Netbacks

The following tables outline the corporate netbacks[1] by country and on a consolidated basis:

Three months ended September 30			2013			2012
Per sales *($/boe)*	Canada[2]	Tunisia	Total	Canada[2]	Tunisia	Total
Realized sales price	**$ 37.76**	**$ 109.81**	**$ 51.17**	$ 29.01	$ 104.68	$ 44.67
Less:						
Royalties	**(3.53)**	**(2.28)**	**(3.30)**	(2.38)	(2.95)	(2.50)
Net production expense [3]	**(16.42)**	**(31.78)**	**(19.28)**	(17.02)	(23.61)	(18.38)
Cash G&A [4]	**(3.00)**	**(5.80)**	**(2.46)**	(1.01)	(8.37)	(2.54)
Corporate netback [1]	**$ 14.81**	**$ 69.95**	**$ 26.13**	$ 8.60	$ 69.75	$ 21.25

Nine months ended September 30			2013			2012
Per sales *($/boe)*	Canada[2]	Tunisia	Total	Canada[2]	Tunisia	Total
Realized sales price	**$ 37.82**	**$ 105.91**	**$ 50.05**	$ 30.08	$ 110.25	$ 41.07
Less:						
Royalties	**(4.27)**	**(2.74)**	**(3.98)**	(3.40)	(3.17)	(3.37)
Net production expense [3]	**(15.64)**	**(27.23)**	**(17.73)**	(15.83)	(24.14)	(16.97)
Cash G&A [4]	**(2.51)**	**(3.96)**	**(2.77)**	(2.59)	(6.08)	(3.07)
Corporate netback [1]	**$ 15.40**	**$ 71.98**	**$ 25.57**	$ 8.26	$ 76.86	$ 17.66

(1) Corporate 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 as divided by the period's sales volumes. Management uses 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 production and operating expense table where this non-IFRS measure is defined.

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

For the current reporting periods, our total corporate netbacks increased 23% and 45%, respectively, as compared to the same periods of 2012. Contributing to these increases were higher Canadian corporate netbacks. For the third quarter, an increase in the Tunisian corporate netback also contributed to the higher reported total netback. Although the Tunisian corporate netback decreased for the year to date as compared to the same period in 2012, the higher proportion of sales volumes from this segment, which has a relatively higher corporate netback, also contributed to the higher reported total netback. The current reporting periods' corporate netbacks, on a boe basis, of $26.13 and $25.57, respectively, were both 51% of their average realized sales price, and were an improvement over the same periods in 2012.

The increases in the Canadian corporate netbacks resulted from a higher proportion of crude oil sales volumes, on a boe basis, as contributed from our focus on the development of our "oily" properties in addition to the change in our commodity portfolio through a recent "oily" acquisition and dry natural gas dispositions as reported since 2011. On our Canadian crude oil sales we receive premium pricing per barrel, despite generally incurring higher production costs on a boe basis, resulting in an increased corporate netback as compared to what we would have received for an equivalent boe of natural gas. The impact of higher production costs as generally occurred on "oily" sales volumes during the current reporting periods was more than offset by the prior periods' reporting of an unfavorable processing and gathering income adjustment which had the effect of increasing the comparable periods' net production costs on a boe basis. In addition, the current reporting periods' Canadian corporate netbacks were positively affected by higher natural gas pricing whereas for the third quarter the netback was negatively affected by higher cash G&A per boe. The Canadian corporate netbacks include cash G&A costs related to our corporate office of $2.75 and $2.19 per boe for the current reporting periods.

Our Tunisian segment's netback for the third quarter, relative to the same period of 2012, increased due to higher crude oil and natural gas prices and, on a boe basis, lower royalties and cash G&A costs. Unfortunately, this favorable pricing was not realized for the year to date, resulting in a lower Tunisian segment netback as compared to the same period in 2012, despite, on a boe basis, lower royalties and cash G&A costs. In addition, our Tunisian segment's year to date netback decreased, on a boe basis, because of an increase in production expense resulting from a greater proportion of sales from our higher operating cost BBT Concession in addition to higher production cost anomalies.

Exploration and Evaluation Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	2013	2012	2013	2012
Canada	**$ 276**	$ 665	**$ 3,831**	$ 2,718
Tunisia	**1,212**	236	**5,749**	4,684
Total	**$ 1,488**	$ 901	**$ 9,580**	$ 7,402

Exploration and evaluation expense for the year to date of $9.6 million was higher compared to the same period of 2012.

During the year to date, we determined that a Canadian exploration well that was drilled and reported within exploration and evaluation assets in 2012, was unsuccessful for petroleum or natural gas reserves. Costs incurred on this Canadian exploratory well of $1.4 million were expensed during the year to date through exploration and evaluation expense.

Also during the year to date, the El Bell 1 ("EB-1") exploration well located on our onshore Sud Remada Permit was drilled and despite encountering hydrocarbons in the target Ordovician zone, following further testing the well was suspended after being evaluated as non-commercial. Because of this, drilling costs as at September 30, 2013 of $3.2 million, including a $0.1 million estimated decommissioning charge, were directly charged to exploration and evaluation expense.

A completion operation was attempted on our TT4 well (0.86 net) to access the lower non-productive interval. Prior to completion, we determined that the objectives of accessing this non-productive interval would not be met and the associated costs of $1.1 million were therefore charged directly to exploration and evaluation expense.

The remaining $3.9 million of costs were mostly comprised of Canadian and Tunisian exploratory lease rental and geological and geophysical costs for the current reporting periods as directly charged to exploration and evaluation expense.

Risk Management Contract (Gains) Losses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2013**	2012	**2013**	2012
Realized gain on commodity contracts	**$ (769)**	$ (182)	**$ (695)**	$ (323)
Unrealized loss (gain) on commodity contracts and swap option	**119**	5,111	**(437)**	(974)
Total	**$ (650)**	$ 4,929	**$ (1,132)**	$ (1,297)

We use commodity price risk management contracts to reduce our exposure to fluctuations in commodity prices. As at September 30, 2013 and 2012, the swap and collar commodity price contracts were reported at their fair values as 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. As at September 30, 2012, the swap option's reported fair value was determined using a Black-Scholes model. This model included the inputs of a forward WTI price and expected WTI price volatility over the remaining term of the swap option. This swap option was settled during 2012 for a nominal amount.

Net Financing Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2013**	2012	**2013**	2012
Interest on bank debt	**$ 1,320**	$ 1,019	**$ 3,952**	$ 3,424
Interest earned on bank deposits	**(37)**	(2)	**(365)**	(7)
Finance charges and fees	**85**	47	**234**	629
Amortization of deferred financing costs	**220**	-	**466**	-
Accretion of decommissioning obligation	**686**	658	**2,066**	2,154
Total	**$ 2,274**	$ 1,722	**$ 6,353**	$ 6,200

The increase in our interest on bank debt for the current reporting periods, as compared to the same periods of 2012, stemmed from higher average interest rates resulting from the terms of a new Canadian facility agreement that was entered into on December 11, 2012. This resulted in an increase in our current reporting periods' effective interest rates to approximately 5.4%, from 4.4% for the same periods of 2012. Partially offsetting these effective interest rate increases was a decrease in each current reporting period's average outstanding long-term debt. An increased average cash position resulted in higher interest earned on bank deposits for the current year to date period.

An increase in the amortization of deferred financing fees during the current reporting periods, as compared to the same periods of 2012, mostly resulted from our international credit facility signed during the first quarter of 2013 and discussed under the "Credit Facilities" section. For the current year to date we have incurred $2.8 million in deferred financing fees.

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

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	2013	2012	2013	2012
Canada	**$ 12,067**	$ 18,132	**$ 39,297**	$ 58,037
Tunisia	**6,274**	7,331	**16,681**	13,872
Total	**$ 18,341**	$ 25,463	**$ 55,978**	$ 71,909
Per sales *($/boe)*	**$ 19.39**	$ 22.36	**$ 20.17**	$ 21.43

DD&A expense for the current reporting periods decreased from the same periods of 2012 due to a lower carrying amount of our Canadian development and production assets, resulting from the reported impairment during 2012 on our Canadian producing properties, in addition to lower Canadian sales volumes. The effect of the lower carrying amount of our Canadian development and production assets also decreased the depletion charge on a boe basis for the current reporting periods, as compared to the same periods in 2012. In addition, an increase in the estimated time period to amortize our undeveloped acreage costs further decreased the DD&A expense. 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 September 30, 2013, we determined that there were no indications of impairment that would warrant an impairment test in any of our cash generating units. At September 30, 2012, we had recognized an impairment charge of $26.5 million.

In addition, we determine that there were no indicators that a recovery of prior periods' impairment was warranted at this time.

Gains on Disposition of Properties

During the year to date, we completed the sale of several petroleum and natural gas properties mostly located throughout Alberta, Canada. Aggregate proceeds were $19.7 million when combined with the final statements of operating adjustments on prior period petroleum and natural gas property sales (2012 - $73.2 million). The carrying amount of these properties, including the disposed decommissioning obligation, was less than the sales proceeds received resulting in a gain of $13.0 million for the year to date as compared to $5.7 million for the same period of 2012.

Income Tax Expense (Recovery)

	Three months ended September 30		Nine months ended September 30	
($ thousands)	2013	2012	2013	2012
Current income tax expense	**$ 1,150**	$ 2,344	**$ 4,089**	$ 4,659
Deferred income tax expense (recovery)	**(1,099)**	1,000	**(1,239)**	622
Total	**$ 51**	$ 3,344	**$ 2,850**	$ 5,281

Current income taxes, mostly relating to our Adam Concession located onshore Tunisia, decreased in the current reporting periods as compared to the same periods of 2012. The third quarter decrease was due to lower sales volumes whereas the year to date decrease was due to lower crude oil pricing.

We had a deferred income tax recovery of $1.2 million for the current reporting year to date period as compared to an expense in the same period of 2012. This recovery resulted from higher tax bases from our BEK permit as deductible from our Adam Concession's taxable income. We have not reported deferred tax assets because it is not probable that we can utilize these assets against future taxable profit.

Net Income (Loss) and Comprehensive Income (Loss)

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per share amounts)	2013	2012	2013	2012
Net income (loss)	**$ 3,812**	$ (12,417)	**$ 12,302**	$ (54,320)
Per share - basic and diluted *($/share)*	**0.02**	(0.06)	**0.06**	(0.25)
Comprehensive income (loss)	**$ 765**	$ (15,887)	**$ 15,998**	$ (57,779)
Per share - basic and diluted *($/share)*	**0.00**	(0.07)	**0.07**	(0.27)
Weighted average shares outstanding - basic and diluted *(thousands)*	**214,188**	214,188	**214,188**	214,188

Our net income of $3.8 million and $12.3 million for the current reporting periods increased, respectively, relative to the net losses in the same periods of 2012. These increases were mostly due to higher corporate netbacks and gains on property dispositions and lower DD&A expenses as compared to the same periods of 2012. In addition, the current year to date reporting period benefited from the realization of the disposition proceeds on a joint arrangement (see "Joint Arrangement") as well as the absence of any impairment of our Canadian development and production assets as compared to the recognized impairment of $26.5 million during the same period of 2012.

Comprehensive income, which includes our net income and a foreign currency translation gain, increased for the current reporting periods as compared to losses in the same periods in 2012. These increases in comprehensive income were consistent with the increases in our net income. For the third quarter we recorded a foreign currency translation loss on marking to market our Tunisian US dollar denominated assets due to the strengthening Canadian dollar, relative to the US dollar. Inversely, for the year to date we recorded a foreign currency translation gain.

Capital Resources, Capital Expenditures and Liquidity

We continue to focus on project economics, scale and repeatability from opportunities in our existing asset base to grow conventional liquids production and test resource play concepts in Canada.

Cash flow for the year to date, cash on deposit, in addition to proceeds from the disposition of Canadian non-core properties, financed the investment in capital, exploration and evaluation expenditures, principal debt repayments and an increase in non-cash working capital. During the year to date, we completed the sale of Canadian non-core properties with associated volumes totalling approximately 510 boe per day.

Cash Flow

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per share amounts)	**2013**	**2012**	**2013**	**2012**
Cash flow from operations	**$ 22,925**	$ 25,119	**$ 48,667**	$ 45,890
Add back (deduct):				
Change in operating non-cash working capital	**(806)**	(4,681)	**12,685**	1,540
Deferred disposition proceeds	**-**	-	**3,051**	-
Decommissioning obligation expenditures	**1,027**	497	**2,440**	2,509
Cash flow(1)	**$ 23,146**	$ 20,935	**$ 66,843**	$ 49,939
Per share - basic and diluted(1)	**$ 0.11**	$ 0.10	**$ 0.31**	$ 0.23
Per sales *($/boe)*(1)	**$ 24.47**	$ 18.39	**$ 24.09**	$ 14.88

(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 operations.

Cash flow of $23.1 million and $66.8 million for the current reporting periods, respectively, increased as compared to the same periods of 2012, as higher corporate netbacks were partially offset by lower Canadian sales volumes. In addition, for the year to date the cash flow increase was due to higher Tunisian sales volumes and a one-time termination of the NZOG Hammamet Pty. Ltd ("NZOG") optional right (see "Joint Arrangement").

Credit Facilities

	September 30	December 31
($ thousands)	**2013**	**2012**
Long-term debt	**$ 75,767**	$ 89,137
Less:		
Working capital excluding mark-to-market derivative contracts	**(10,662)**	(16,754)
Net debt(1)	**$ 65,105**	$ 72,383

(1) Net debt and working capital excluding mark-to-market derivative 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.

Our net debt of $65.1 million as at September 30, 2013, decreased relative to $72.4 million as at December 31, 2012 due to our year to date cash flow and proceeds on property dispositions exceeding our $77.1 million in capital, exploration and evaluation expenditures. During the current year to date reporting period, we made a repayment of $11.0 million of outstanding principal in addition to paying $2.8 million in deferred financing costs related to the signing of a new international credit facility as secured by our Tunisian assets and extending the revolving period of our existing Canadian credit facility. These payments, which lowered the carrying amount of our long-term debt, were also included in the decrease in our working capital.

On December 11, 2012, we signed a new Canadian reserve-based 364 day revolving credit facility (the "Canadian Revolving Term Credit Facility") with a syndicate of Canadian banks with a maximum availability of $115.0 million. During the current reporting periods, we extended the revolving period through to September 26, 2014. In the event that the revolving period is not extended by the banks prior to this date, all amounts then outstanding under the Canadian Revolving Term Credit Facility must be repaid before September 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. During the current reporting periods, we made debt repayments of $11.0 million bringing our total outstanding draws on the Canadian Revolving Term Credit Facility at September 30, 2013 to $78.5 million (December 31, 2012 - $89.5 million). At September 30, 2013, we had available credit of $36.5 million from the Canadian Revolving Term Credit Facility (December 31, 2012 - $25.5 million). Unamortized deferred financing costs of approximately $0.3 million remained at September 30, 2013 ($0.4 million at December 31, 2012) and will be amortized through the existing term of this facility.

The Canadian 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. Interest payable on amounts drawn on this facility vary based on the applicable pricing rate as combined with either the Canadian prime, U.S. Base rate, U.S. LIBOR or Bankers' Acceptances depending on the borrowing option we select. 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 and amortization cannot be greater than 4:1 as determined on a rolling four quarter basis for the most current fiscal quarter. As at September 30, 2013, 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 ("International Credit Facility") for a term of five years with an international bank. The maximum availability under this facility is US$46.5 million. The International Credit Facility is subject to a semi-annual review and redetermination, where the available amount will be reassessed and 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 U.S. LIBOR. As at September 30, 2013, we had no outstanding drawings against the International Credit Facility. Unamortized deferred financing costs of approximately $2.5 million remained at September 30, 2013 and will be amortized through to the anticipated expiry of the facility in March 2018.

Capital Expenditures

Three months ended September 30				2013				2012
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 493**	**$ -**	**$ -**	**$ 493**	$ 242	$ -	$ -	$ 242
Drilling and completions	**6,655**	**8,115**	**-**	**14,770**	2,642	17,057	-	19,699
Facilities and equipment	**2,602**	**974**	**-**	**3,576**	657	1,180	-	1,837
Field expenditures	**9,750**	**9,089**	**-**	**18,839**	3,541	18,237	-	21,778
Capitalized G&A	**262**	**1,848**	**-**	**2,110**	404	481	-	885
Furniture and equipment	**-**	**-**	**12**	**12**	-	-	10	10
Property acquisitions	**-**	**-**	**-**	**-**	1	-	-	1
Total	**$ 10,012**	**$ 10,937**	**$ 12**	**$ 20,961**	$ 3,946	$ 18,718	$ 10	$ 22,674
Proceeds from dispositions	**$ 3,283**	**$ -**	**$ -**	**$ 3,283**	$ 1,425	$ -	$ -	$ 1,425

Nine months ended September 30				2013				2012
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 3,255**	**$ -**	**$ -**	**$ 3,255**	$ 819	$ -	$ -	$ 819
Drilling and completions	**21,454**	**23,377**	**-**	**44,831**	14,347	30,807	-	45,154
Facilities and equipment	**7,160**	**8,597**	**-**	**15,757**	5,908	4,273	-	10,181
Field expenditures	**31,869**	**31,974**	**-**	**63,843**	21,074	35,080	-	56,154
Capitalized G&A	**829**	**4,302**	**-**	**5,131**	1,261	1,651	-	2,912
Furniture and equipment	**-**	**-**	**92**	**92**	-	-	61	61
Property acquisitions	**-**	**-**	**-**	**-**	76	-	-	76
Total	**$ 32,698**	**$ 36,276**	**$ 92**	**$ 69,066**	$ 22,411	$ 36,731	$ 61	$ 59,203
Proceeds from dispositions	**$ 19,703**	**$ -**	**$ -**	**$ 19,703**	$ 73,200	$ -	$ -	$ 73,200

Wells Drilled

A summary of our drilling activities for the third quarter and year to date is as follows:

Three months ended September 30, 2013	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Exploration oil wells	-	**-**	-	**-**	-	**-**
Development oil wells	1.00	**0.86**	3.00	**3.00**	4.00	**3.86**
Total	1.00	**0.86**	3.00	**3.00**	4.00	**3.86**

Nine months ended September 30, 2013	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Exploration oil wells	-	**-**	4.00	**2.24**	4.00	**2.24**
Development oil wells	4.00	**2.63**	6.00	**4.37**	10.00	**7.00**
Dry wells	1.00	**0.86**	-	**-**	1.00	**0.86**
Total	5.00	**3.49**	10.00	**6.61**	15.00	**10.10**

Canada Capital Expenditures

Our Canadian activity in the third quarter of 2013 consisted of a three (3.0 net) well drilling program on the acquired Albright and Beaverlodge properties in our Grande Prairie core area. These three new Dunvegan horizontal oil wells were all brought on production within six weeks of being spud, taking advantage of our infrastructure ownership in the area. The total wells costs through to tie-in for all wells were below our estimates (averaging $2.4 million per well), while production results have exceeded our estimates with initial 30 day rates averaging 220 boe per day (86% oil) per well. Net production on the acquired properties has increased from 280 boe per day in January 2013 to over 1,000 boe per day currently. Up to 30 more locations have been identified on our acreage, six (5.0 net) of which are currently being prepared for drilling operations to commence late in the fourth quarter of 2013 and through the first quarter of 2014.

At Karr, all five (1.86 net) previously drilled horizontal Dunvegan oil wells continue to meet or exceed internal production expectations. Late in the third quarter, the operator commenced a four (1.2 net) well drilling program at Karr, the first of which has been drilled and cased. Up to 23 additional locations have been identified on our acreage at Karr.

Additional opportunities currently budgeted for 2014 include horizontal drilling locations in the Grande Prairie core area at Gold Creek/Karr (Montney oil, Doig oil, Charlie Lake oil), Grovedale (Doe Creek oil) and Gordondale (Halfway oil). We also plan to begin developing our significant land position at Umbach/Birley in north eastern British Columbia by drilling our first horizontal well targeting a Montney liquids rich natural gas prospect.

Tunisia Capital Expenditures

Our BBT Concession's capital activity in the third quarter of 2013 included the drilling and completion of the TT20 well (0.86 net) and the completion of the TT21 well (0.86 net). Gross drilling and completion costs of $3.7 million ($3.2 million net) on our TT20 well demonstrate that we are currently capable of drilling and completing a vertical well at or below $4.0 million with a projected future cost of $3.5 million. After completing the TT20 well, the drilling rig was moved to the TT23 (0.86 net) location in August at which time ETAP expressed an objection to the previously approved location. We engaged with ETAP in technical meetings to determine the next, mutually agreed upon, locations.

Our TT20 well was drilled as a vertical Ordovician development well and encountered a thick reservoir section determined to be hydrocarbon bearing on log evaluations. The well was completed in August with a hydraulic fracture completion. Upon cleanup the well had recovered in excess of 100% of the load fluid placed during the completion with an increasing oil cut after a 24 hour flow test. The well was suspended pending the installation of a jet pump in order to conduct a longer term test.

It was agreed upon with ETAP that the TT12 horizontal well will be converted to injection as a pressure support/water injection pilot project. Rental water treatment equipment will be moved into position during the fourth quarter of 2013 at which time injection will commence.

On the non-operated Adam Concession and BEK permit, a sidetrack was completed on the Karma-2 well (0.05 net) and the 1,250 km^2 3D seismic acquired is being processed and interpreted. This Karma-2 sidetrack well is on production from the Silurian Acacus layers at gross rates of approximately 600 barrels of oil per day and 3.5 million cubic feet of natural gas per day. The Karma-2 sidetrack well penetrated the Ordovician and tested rates from an openhole section of 1,450 barrels per day of condensate and 12 million cubic feet of natural gas per day. The Ordovician interval is suspended subject to future infrastructure capacity.

Rationalization of Non-Core Properties

During the current year to date, we completed the sale of several non-core petroleum and natural gas properties located throughout Alberta, Canada, for aggregate net proceeds of $19.7 million, after including the final statements of adjustments for these and prior period dispositions. The non-core properties sold included Red Creek, Edwand, Thonbury-Portage and portions of Gordondale, Lochend, and Harmattan. Our production from these and the other sold properties was approximately 510 boe per day. The funds received for these dispositions were used to partially fund our capital program expenditures of $69.1 million.

Joint Arrangement

On March 19, 2013, NZOG acknowledged that it had given a negative final investment decision ("FID") as defined under the terms of our farmout agreement (the "Farmout Agreement"). This terminated NZOG's optional right to complete its earning and acquisition of an interest in the Cosmos Concession per the terms of the Farmout Agreement. Given the termination of this optional right, we reported the initial US$3.0 million cash proceeds we received from NZOG as realized through the line item foreign exchange & other (gains) and losses on the condensed consolidated statements of operations and comprehensive income (loss) during the year to date 2013.

Decommissioning Obligation

At September 30, 2013, we have decommissioning obligations of $101.8 million (December 31, 2012 - $110.5 million) for the future abandonment and reclamation of our properties. This decrease in the decommissioning obligation resulted from non-core property dispositions, which removed $9.4 million of obligations in addition to $2.4 million of abandonment and reclamation expenditures.

As at September 30, 2013 and December 31, 2012, 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. A risk-free interest rate of 2.5% was also used in order to present value the obligation.

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 $2.1 million, respectively, were comparable to the charges reported during the same periods in 2012. During the current year to date reporting period, additions to the decommissioning liability of $1.0 million were due to the current period's drilling activities (2012 - $2.0 million).

Outstanding Share Data

Authorized:

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

Details of share capital, options and warrants outstanding are as follows:

	September 30 2013	December 31 2012
Common shares outstanding	**214,187,681**	214,187,681
Share options	**14,438,315**	13,860,866
Share purchase warrants	**-**	1,279,000
Fully diluted common shares	**228,625,996**	229,327,547
Weighted average common shares - basic and diluted	**214,187,681**	214,187,681

On June 30, 2013, 1,279,000 share purchase warrants with an exercise price of $3.25 per common share expired unexercised.

As at November 13, 2013, we had issued 214,187,681 common shares and had 14,345,063 outstanding share options.

Commodity Price Risk Management Contracts

To mitigate commodity price risk, our management, upon approval of the Board of Directors, has 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 Board of Directors approved hedging policy which determines which commodities can be hedged, the maximum notional volume of hedged production, the reference indexed price and terms of hedges.

Unsettled risk management contracts are recognized at their approximated fair value on the date of the 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 and to a lesser extent the foreign exchange impact of the translation from the US to Canadian dollar. Changes in the fair value between reporting periods are recognized in net income (loss) as unrealized risk management contract gains or losses. Realized risk management contract gains or losses are recognized in net income (loss) on unwinding of the financial derivative contract term. While risk management contracts may have opportunity costs when realized commodity prices exceed the contracted price, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such financing techniques.

As at September 30, 2013, we had the following commodity price contracts with an estimated fair value of $0.4 million:

Indexed Price	Notional Volumes	Company's Received Price	Remaining period
AECO	7,000 GJ/d	$3.20/GJ	October 1, 2013 to December 31, 2013
AECO	3,000 GJ/d	$3.40/GJ	October 1, 2013 to October 31, 2013
AECO	5,000 GJ/d	$3.25/GJ to $3.50/GJ	January 1, 2014 to December 31, 2014
Brent	500 bbl/d	$95.00 US/bbl to $115.50 US/bbl	October 1, 2013 to December 31, 2013

Subsequent to September 30, 2013, we entered into the following contract:

Indexed Price	Notional Volumes	Company's Received Price	Remaining period
Brent	500 bbl/d	$98.00 US/bbl to $108.00 US/bbl	January 1, 2014 to December 31, 2014

Outlook

Our corporate guidance for the balance of 2013 remains on track, despite the downward re-forecasted Tunisian annual production volumes as these decreases have been offset by our Canadian segment's growth and improved results. As announced on August 14, 2013, our corporate guidance for 2013 remains as follows:

	2013 Guidance		
($ millions, except boe/d)	**Consolidated**	**International**	**Canada**
Production *(boe/d)*	9,350 - 10,000	2,000 - 2,250	7,350 - 7,750
Cash flow	$85 - $90	$45 - $48	$40 - $42
Capital expenditures	$95 - $100	$51 - $53	$44 - $47
Net debt	$60 - $65	-	$60 - $65
Credit facilities	$161.5	US $46.5	$115

Our Board of Directors has approved an initial capital budget for 2014 of $85 million, of which $49 million has been allocated to Canada and $36 million to Tunisia. Our management is currently finalizing a detailed review on the timing of 2014 capital spending plans and anticipates releasing our 2014 guidance by mid-December.

Our focus for 2014 will be on increasing our oil weighting in western Canada. Our Canadian capital program will be directed almost exclusively toward oil opportunities along with continued non-core asset rationalization and a focus on improving capital and operating efficiencies. In Tunisia, we will continue to appraise and develop our BBT concession along with pursuing various strategic initiatives intended to improve a low market valuation relative to our Canadian peers which can be attributed to the hybrid nature of our asset base. The strength of our balance sheet will enable us to pursue additional acquisition opportunities in our core area of Grande Prairie in what is continuing to be an exciting and robust asset market.

Quarterly Information

Summarized information by quarter for the two years ended September 30, 2013, appears below:

	Sept. 30 2013	Jun. 30 2013	Mar. 31 2013	Dec. 31 2012	Sept. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011
OPERATIONS								
Production								
Oil *(bbl/d)*	**3,456**	3,298	3,565	4,035	3,516	3,195	3,819	4,206
Natural gas liquids *(bbl/d)*	**753**	874	1,005	1,003	1,141	1,122	1,202	1,591
Natural gas *(mcf/d)*	**35,820**	34,458	37,736	39,585	43,839	43,387	51,445	55,927
Average daily production *(boe/d)*	**10,180**	9,916	10,860	11,636	11,964	11,548	13,596	15,119
Sales								
Oil *(bbl/d)*	**3,558**	3,588	2,710	4,264	3,929	2,385	3,846	4,282
Natural gas liquids *(bbl/d)*	**753**	874	1,005	1,003	1,141	1,122	1,202	1,591
Natural gas *(mcf/d)*	**35,820**	34,458	37,736	39,584	43,839	43,387	51,445	55,927
Average daily sales *(boe/d)*	**10,282**	10,205	10,006	11,865	12,377	10,738	13,623	15,195
Sales Prices								
Average oil price *($/bbl)*	**$ 104.46**	$ 98.07	$ 95.03	$ 97.72	$ 95.61	$ 89.11	$ 101.06	$ 97.11
Average natural gas liquids price *($/bbl)*	**$ 62.36**	$ 55.06	$ 58.85	$ 57.71	$ 56.42	$ 55.46	$ 70.66	$ 71.23
Average natural gas price *($/mcf)*	**$ 3.00**	$ 4.13	$ 3.72	$ 3.39	$ 2.57	$ 2.08	$ 2.27	$ 3.31
Corporate Netbacks(1)								
Average commodity pricing *($/boe)*	**$ 51.17**	$ 53.13	$ 45.70	$ 51.30	$ 44.67	$ 33.97	$ 43.35	$ 47.00
Royalties *($/boe)*	**$ (3.30)**	$ (4.88)	$ (3.79)	$ (0.64)	$ (2.50)	$ (3.29)	$ (4.22)	$ (6.03)
Net production expenses *($/boe)*(1)	**$ (19.28)**	$ (17.31)	$ (16.52)	$ (18.98)	$ (18.38)	$ (14.46)	$ (17.65)	$ (17.75)
Cash G&A *($/boe)*(1)	**$ (2.46)**	$ (3.02)	$ (2.83)	$ (4.48)	$ (2.54)	$ (3.74)	$ (3.03)	$ (5.13)
Corporate netbacks *($/boe)*(1)	**$ 26.13**	$ 27.92	$ 22.56	$ 27.20	$ 21.25	$ 12.48	$ 18.45	$ 18.10
Wells Drilled (net)								
Oil	**3.86**	1.77	3.61	2.96	1.11	0.86	3.16	6.12
Gas	**-**	-	-	-	-	-	1.00	1.02
Dry	**-**	0.86	-	-	-	0.86	0.10	-
Total wells drilled (net)	**3.86**	2.63	3.61	2.96	1.11	1.72	4.26	7.14
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties(2)	**$ 45,285**	$ 44,805	$ 37,740	$ 55,303	$ 48,012	$ 29,979	$ 48,509	$ 57,274
Cash flow(1)(2)	**$ 23,146**	$ 22,179	$ 21,518	$ 28,757	$ 20,935	$ 9,830	$ 19,174	$ 23,950
Per share - basic and diluted *($/share)*	**$ 0.11**	$ 0.10	$ 0.10	$ 0.13	$ 0.10	$ 0.05	$ 0.09	$ 0.11
Net income (loss)(2)(3)	**$ 3,812**	$ 3,990	$ 4,500	$ (36,708)	$ (12,417)	$ (24,812)	$ (17,091)	$ (58,077)
Per share - basic and diluted *($/share)*	**$ 0.02**	$ 0.02	$ 0.02	$ (0.17)	$ (0.06)	$ (0.12)	$ (0.08)	$ (0.27)
Capital expenditures	**$ 20,961**	$ 23,059	$ 25,046	$ 50,456	$ 22,674	$ 13,083	$ 23,446	$ 26,343
Net debt(1)	**$ 65,105**	$ 66,340	$ 64,440	$ 72,383	$ 80,428	$ 77,092	$ 89,182	$ 134,900
Total assets	**$ 593,192**	$ 621,143	$ 617,459	$ 622,476	$ 628,542	$ 637,238	$ 692,023	$ 745,403
Common Shares *(thousands)*								
Weighted average during period - basic and diluted	**214,188**	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, net debt, corporate 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 $43.0 million, $26.5 million and $55.5 million in impairment charges against Canadian properties for the three months ended December 31, 2011, June 30, 2012 and December 31, 2012, respectively.

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 the third quarter of 2013, has 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 since the fourth quarter of 2011 and increased Canadian crude oil production resulting from a drilling program which began in 2013. When combined with the effect of the Brent, Edmonton par and AECO benchmarks which generally trended down until the second quarter of 2012 and have since trended upwards, petroleum and natural gas revenues, net of royalties, have recovered from the effects of the non-core property disposition program. This, in turn, has generated sufficient cash flow to reduce our net debt and has allowed us to avoid having to access the equity markets.

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 corporate netback per boe declined for these quarters. Further, for the fourth quarter of 2011 and second and fourth quarters of 2012, $43.0 million, $26.5 million and $55.5 million, respectively, of impairment charges were reported against our Canadian CGUs 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 historically been focused on the Canadian drilling and completions programs but during the second quarter of 2012 shifted, generally, in favor of Tunisian organic growth.

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, 2012 (“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 materially adversely impacted.

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

Tunisian Political and Security Risk Update

The political stability and resulting security situation in Tunisia have taken several steps back recently after a four to five month period of relative calm, which had been viewed as a signal of progress. The majority of the timing and motivation of the acts of violence is politically motivated, perpetrated by parties’ intent on de-stabilizing the Tunisian political process and not directed towards our company or foreign investment in Tunisia. In response to the destabilized conditions, we have increased our security preparedness and threat assessment protocols. The existing instability serves to increase the logistical complexity and security related costs of our operations. We expect that the current instability will continue during the balance of the year as we approach the promised elections. We will continue to carefully monitor the situation and manage for the long-term success of our Tunisian business while maintaining a priority on the immediate security of our personnel and stakeholders. The destabilized conditions in Tunisia may result in unforeseen delays in the execution of our operational program.

New Accounting Standards and Amendment

On January 1, 2013, we adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), and fair value measurements (IFRS 13). We also adopted the amendment to IFRS 7 “Financial Instruments: Disclosures” to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar agreements.

The adoption of these standards and amendment had no impact on the amounts recorded in the condensed consolidated financial statements as at September 30, 2013 nor in the annual consolidated financial statements as at December 31, 2012.

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in our internal controls over financial reporting were identified during the three months ended September 30, 2013, 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 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: the volume and product mix of our oil and natural gas production on certain newly drilled wells, and the anticipated production volumes therefrom; the anticipated timing of the regulatory response regarding the approval of future drilling on our BBT Concession; the operations to be conducted, wells to be drilled and/or completed and the timing thereof on certain of Chinook's 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; as well as management's future expectations regarding production, cash flow, capital expenditures, net debt and credit facilities 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 anticipated 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, the impact of increasing competition, our ability to add production and reserves through development and exploitation activities, the results of seismic and other appraisal activities (including waterflood modeling and seismic data gathering); certain commodity price and other cost assumptions, the continued availability of adequate debt and equity 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 risk 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, the continued impact of shut-in production, environmental risks, competition from other producers, inability to retain drilling rigs and other services, 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 ability 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 our annual information form for the year ended December 31, 2012 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.