2013 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 years ended December 31, 2013 and 2012 and should be read in conjunction with our 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 March 25, 2014.

The terms "fourth quarter" and "reported year" or similar terms are used throughout this document and refer to the three months and year ended December 31, 2013, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three month and year ended December 31, 2013. The term "same period of 2012" or similar terms are used throughout this document and refer to the three months or year ended December 31, 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, 2013 ("AIF"), can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The consolidated financial statements and comparative information for the years ended December 31, 2013 and 2012 have been prepared in accordance with International Financial Reporting Standards ("IFRS"). 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, netbacks, net debt, net production expense and cash G&A 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 oil and natural gas exploration and development company with predominately natural gas and liquids reserves in western Canada and 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 ("TSX") under the symbol "CKE". Our head office and principal address is Suite 700, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

Our operating and reportable segments are as follows:

- Canada – includes our Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in North Western Alberta and North Eastern 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 December 31		Year ended December 31	
	2013	2012	**2013**	2012
OPERATIONS				
Production				
Oil (bbl/d)	**3,356**	4,035	**3,418**	3,642
Natural gas liquids *(bbl/d)*	**722**	1,003	**838**	1,117
Natural gas *(mcf/d)*	**33,612**	39,585	**35,396**	44,548
Average daily production *(boe/d)*	**9,680**	11,636	**10,155**	12,184
Sales				
Oil *(bbl/d)*	**3,725**	4,264	**3,398**	3,609
Natural gas liquids *(bbl/d)*	**722**	1,003	**838**	1,117
Natural gas *(mcf/d)*	**33,612**	39,584	**35,396**	44,548
Average daily sales *(boe/d)*	**10,049**	11,864	**10,136**	12,151
Sales Prices				
Average oil price *($/bbl)*	**$ 98.57**	$ 97.72	**$ 99.29**	$ 96.61
Average natural gas liquids price *($/bbl)*	**$ 63.74**	$ 57.71	**$ 59.72**	$ 60.26
Average natural gas price *($/mcf)*	**$ 3.99**	$ 3.39	**$ 3.70**	$ 2.55
Netback[1]				
Average commodity pricing *($/boe)*	**$ 54.46**	$ 51.30	**$ 51.16**	$ 43.58
Royalties *($/boe)*	**$ (4.61)**	$ (0.64)	**$ (4.14)**	$ (2.70)
Net production expenses *($/boe)*[1]	**$ (19.32)**	$ (18.98)	**$ (18.13)**	$ (17.46)
Cash G&A *($/boe)*[1]	**$ (3.10)**	$ (4.48)	**$ (2.85)**	$ (3.42)
Netback *($/boe)*[1]	**$ 27.43**	$ 27.20	**$ 26.04**	$ 20.00
Wells Drilled (net)				
Oil	**1.65**	2.96	**10.89**	8.09
Gas	**-**	-	**-**	1.00
Dry	**-**	-	**0.86**	0.96
Total wells drilled (net)	**1.65**	2.96	**11.75**	10.05
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 46,088**	$ 55,303	**$ 173,918**	$ 181,802
Cash flow[1]	**$ 20,179**	$ 28,758	**$ 87,022**	$ 78,697
Per share – basic and diluted *($/share)*	**$ 0.09**	$ 0.13	**$ 0.41**	$ 0.37
Net loss	**$ (39,002)**	$ (36,708)	**$ (26,700)**	$ (91,028)
Per share – basic and diluted *($/share)*	**$ (0.18)**	$ (0.17)	**$ (0.13)**	$ (0.42)
Capital expenditures	**$ 14,162**	$ 50,456	**$ 83,228**	$ 109,657
Net debt[1]	**$ 61,849**	$ 72,383	**$ 61,849**	$ 72,383
Total assets	**$ 555,341**	$ 622,476	**$ 555,341**	$ 622,476
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, 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.

2013 Annual Guidance and Financial Highlights

A summary of our revised 2013 guidance, as announced on August 14, 2013, and a review of our actual results:

($ millions, except boe/d)	2013 Guidance			2013 Actual		
	Consolidated	International	Canada	Consolidated	International	Canada
Production *(boe/d)*	9,350 - 10,000	2,000 - 2,250	7,350 - 7,750	**10,155**	**1,917**	**8,238**
Cash flow	$85 - $90	$45 - $48	$40 - $42	**$ 87**	**$ 46**	**$ 41**
Capital, evaluation and decommissioning expenditures	$95 - $100	$51 - $53	$44 - $47	**$ 96**	**$ 49**	**$ 47**
Net debt	$60 - $65	-	$60 - $65	**$ 62**	**-**	**$ 62**
Maximum available credit	$161.5	US $46.5	$115	**$ 161.5**	**US $46.5**	**$ 115**

Our production for 2013 is above guidance reflecting the positive results of our 2013 drilling program in Canada which focused on opportunities in our Grande Prairie area with new production predominately comprised of crude oil. In Tunisia, we revised down our original production guidance from 2,150 – 2,450 boe per day and capital, evaluation and decommissioning expenditures from $58 – $60 million. This reflects management's decision to use more sparingly, but strategically, the higher cost horizontal wells and to continue development of the BBT Concession with more economical vertical wells, although with their lower associated production. Actual production and capital expenditures for Tunisia were further reduced relative to revised guidance as during the fourth quarter new governmental applications and approval processes resulted in the delay of our BBT Concession's drilling campaign on pre-approved drilling sites.

Cash flow during the year ended 2013 was consistent with our guidance as our Canadian segment's higher crude oil sales volumes, with their higher associated netback as compared to natural gas, was offset by lower Tunisian sales volumes. We also accomplished our net debt guidance on the backs of meeting production, cash flow, and capital, evaluation and decommissioning expenditures' guidance.

Operations

Petroleum and Natural Gas Production and Sales Volumes

Three months ended December 31	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	**1,840**	**722**	**32,287**	**7,943**	1,514	1,003	38,529	8,939
Tunisia	**1,516**	**-**	**1,325**	**1,737**	2,521	-	1,055	2,697
Total[(1)]	**3,356**	**722**	**33,612**	**9,680**	4,035	1,003	39,584	11,636
Sales								
Canada	**1,839**	**722**	**32,287**	**7,943**	1,514	1,003	38,529	8,939
Tunisia	**1,886**	**-**	**1,325**	**2,107**	2,750	-	1,055	2,926
Total[(1)]	**3,725**	**722**	**33,612**	**10,049**	4,264	1,003	39,584	11,865

Year ended December 31	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	**1,713**	**838**	**34,125**	**8,238**	1,790	1,117	43,510	10,159
Tunisia	**1,705**	**-**	**1,271**	**1,917**	1,852	-	1,038	2,025
Total[(1)]	**3,418**	**838**	**35,396**	**10,155**	3,642	1,117	44,548	12,184
Sales								
Canada	**1,713**	**838**	**34,125**	**8,238**	1,790	1,117	43,510	10,159
Tunisia	**1,685**	**-**	**1,271**	**1,897**	1,819	-	1,038	1,992
Total[(1)]	**3,398**	**838**	**35,396**	**10,136**	3,609	1,117	44,548	12,151

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

Canadian crude oil production continued at the rate established in the third quarter of 2013, which saw us achieve our highest production levels since the first quarter of 2012. This improvement is due to the development of recently acquired properties in the Grande Prairie area. During the reported year we drilled six (4.5 net) wells on our Albright property, adding approximately 800 boe per day (82% crude oil) of production. Even though our crude oil production during the fourth quarter increased over the same quarter of 2012, overall production levels of our Canadian segment decreased approximately 995 and 1,920 boe per day, as compared to the same periods of 2012. These decreases included approximately 1,100 and 2,200 boe per day of reduced production, 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.

During the reported year, our Tunisian production volumes were primarily generated from our development of the Bir Ben Tartar Concession ("BBT"). We drilled two successful vertical (1.72 net) wells on our BBT Concession, bringing our total number of producing wells on this Concession to 13 (11.18 net). Our Tunisian production volumes of 1,737 boe per day and 1,917 boe per day for the fourth quarter and year ended 2013, decreased by 36% and 5% relative to the same periods of 2012 as natural declines from the initial horizontal development exceeded new adds from our two vertical completions. During the third quarter of 2013, we were informed by the Tunisian Regulatory Authority that a new application and approval process, that better addressed the risk to groundwater 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 submitted during the fourth quarter. Once this application was approved we were able to spud our TT15 well prior to the end of the fourth quarter; however, the application delay caused us not to bring on any incremental production during the fourth quarter of 2013 to offset natural production declines. The TT15 well was completed in January 2014 and net production during February 2014 was approximately 170 barrels of crude oil per day. During the first quarter of 2014 we drilled and completed our TT28 and TT18 wells and commenced drilling the TT19 well. TT28 and TT18 are currently undergoing production testing. These four wells are part of a six well (5.16 net) vertical program on the BBT Concession that is planned for the first half of 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 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.

Drilling and completion expenditures for the fourth quarter totalled $10.1 million (same quarter of 2012 – $15.8 million), which included our Tunisian segment's drilling and completion expenditures of $4.2 million (same quarter of 2012 – $12.0 million). Fourth quarter Tunisian activity included the spudding of our TT15 well (0.86 net), the optimization of our TT8 well by running a velocity string to improve the well performance and stabilise the flow rate, and the preparation required to convert the TT12 horizontal well to a water injection well.

We continue to monitor costs, drilling efficiencies and well performance and adjust our near term BBT development plans accordingly. Completed vertical well costs have improved materially due to substantial well cost reductions. These resulted from improved optimization of drilling and completions from over $5.0 million, on a gross basis in 2012 to $4.0 million today. 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.

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 servicing by a rig. 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 fourth quarter were $5.9 million (comparable quarter of 2012 – $3.8 million). They included costs associated with drilling one well (0.5 net) on our Albright property which was completed during the first quarter of 2014. In addition, our partner completed the drilling of four wells (1.2 net) and the completion of three of those wells (0.8 net) at our Karr property.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended December 31			2013			2012
($ thousands, except per unit amounts)	Canada	Tunisia	Total[1]	Canada	Tunisia	Total[1]
Oil sales	**$ 13,736**	**$ 20,041**	**$ 33,777**	$ 10,925	$ 27,418	$ 38,343
$/bbl	**81.18**	**115.53**	**98.57**	78.43	108.37	97.72
Natural gas liquids sales	**$ 4,235**	**$ -**	**$ 4,235**	$ 5,325	$ -	$ 5,325
$/bbl	**63.74**	**-**	**63.74**	57.71	-	57.71
Natural gas sales	**$ 10,591**	**$ 1,749**	**$ 12,340**	$ 10,947	$ 1,387	$ 12,334
$/mcf	**3.57**	**14.35**	**3.99**	3.09	14.29	3.39
Petroleum and natural gas revenue	**$ 28,562**	**$ 21,790**	**$ 50,352**	$ 27,197	$ 28,805	$ 56,002
$/boe	**39.09**	**112.44**	**54.46**	33.07	106.99	51.30

Year ended December 31			2013			2012
($ thousands, except per unit amounts)	Canada	Tunisia	Total[1]	Canada	Tunisia	Total[1]
Oil sales	**$ 55,395**	**$ 67,771**	**$ 123,166**	$ 54,011	$ 73,601	$ 127,612
$/bbl	**88.60**	**110.17**	**99.29**	82.44	110.55	96.61
Natural gas liquids sales	**$ 18,261**	**$ -**	**$ 18,261**	$ 24,637	$ -	$ 24,637
$/bbl	**59.72**	**-**	**59.72**	60.26	-	60.26
Natural gas sales	**$ 40,991**	**$ 6,834**	**$ 47,825**	$ 35,644	$ 5,902	$ 41,546
$/mcf	**3.29**	**14.73**	**3.70**	2.24	15.53	2.55
Petroleum and natural gas revenue	**$ 114,647**	**$ 74,605**	**$ 189,252**	$ 114,292	$ 79,503	$ 193,795
$/boe	**38.13**	**107.74**	**51.16**	30.74	109.05	43.58

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

Petroleum and natural gas revenues of $50.4 million and $189.3 million during the current reporting periods decreased relative to the same periods of 2012. Higher crude oil and natural gas pricing in Canada as well as an increase in Canadian crude oil sales volumes were more than offset by the decrease in Tunisian sales volumes.

Canadian Petroleum and Natural Gas Revenue and Prices

Our Canadian petroleum and natural gas revenue increased during the fourth quarter and was consistent during the reported year relative to the same periods of 2012. During the fourth 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. These increased crude oil sales volumes are the result of our focus on development of our oil properties in addition to the change in our commodity production portfolio resulting from both oil focused acquisitions and dry natural gas weighted dispositions. Similarly for the year ended, comparable crude oil sales volumes, as combined with higher crude oil and natural gas pricing, were offset by lower natural gas volumes. All Canadian pricing benchmarks increased in the current reporting periods as compared to the same periods in 2012.

Tunisian Petroleum and Natural Gas Revenue and Prices

Our Tunisian petroleum and natural gas revenue for the current reporting periods decreased as compared to the same periods of 2012 due to lower sales volumes from our BBT Concession and lower petroleum and natural gas pricing for the reported year. For the fourth quarter, the decrease in our Tunisian petroleum and natural gas revenue was partially offset by an increase in the average realized sales price resulting from the strengthening US dollar.

Benchmark Prices

	Three months ended December 31		Year ended December 31	
	2013	2012	2013	2012
Oil				
Edmonton par *($/bbl)*	**$ 86.32**	$ 84.03	**$ 92.96**	$ 86.19
Brent *($US/bbl)*	**$ 109.35**	$ 110.44	**$ 108.52**	$ 111.96
Natural gas liquids				
WTI[1] *($US/bbl)*	**$ 97.46**	$ 88.18	**$ 97.97**	$ 94.23
Natural gas				
AECO *($/mcf)*	**$ 3.59**	$ 3.26	**$ 3.22**	$ 2.42

(1) West Texas Intermediate

Crude Oil Pricing

Our respective average realized crude oil sales price for the current reporting periods of $98.57 and $99.29 per barrel increased from $97.72 and $96.61 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 US dollar denominated Tunisian crude oil price was lower during the reported year, as compared to the same period of 2012, but was comparable as reported in Canadian dollars due to the relative strengthening of the US dollar. During the fourth quarter, this strengthening US dollar more than offset the decrease in the benchmark pricing and as a result our reported realized crude oil price was higher 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. Our realized natural gas liquids price of $59.72 per barrel was relatively consistent with the same period of 2012. 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 year ended decreased to 64% from 70% in the same period of 2012.

Natural Gas Pricing

Our respective Canadian realized natural gas price of $3.57 and $3.29 per mcf for the current reporting periods showed significant improvement from the $3.09 and $2.24 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 December 31			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 3,507**	**$ 757**	**$ 4,264**	$ 125	$ 574	$ 699
Per sales *($/boe)*	**$ 4.80**	**$ 3.90**	**$ 4.61**	$ 0.15	$ 2.13	$ 0.64
Percent of Revenues *(%)*	**12**	**3**	**8**	0	2	1

Year ended December 31			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 13,214**	**$ 2,120**	**$ 15,334**	$ 9,963	$ 2,030	$ 11,993
Per sales *($/boe)*	**$ 4.39**	**$ 3.06**	**$ 4.14**	$ 2.68	$ 2.78	$ 2.70
Percent of Revenues *(%)*	**12**	**3**	**8**	9	3	6

For the current reporting periods, our royalties of $4.3 million and $15.3 million increased relative to the same periods of 2012 due to the absence of a prior period gas cost allowance recovery as reported during the fourth quarter of 2012. This also had the effect of increasing the Canadian royalty as a percentage of sales. In addition, higher Canadian crude oil and natural gas pricing also led to higher Canadian royalties on a boe basis.

The increase in Tunisian royalties during the current reporting periods resulted from higher Tunisian sales from our royalty paying Adam Concession, as well as the relative strengthening of the US dollar. In addition, for the fourth quarter the increased royalty per boe resulted from higher benchmark pricing. 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 production sharing contract between ourselves and ETAP.

Production and Operating Expense

Three months ended December 31			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating expense	**$ 12,735**	**$ 6,299**	**$ 19,034**	$ 16,703	$ 6,707	$ 23,410
Less:						
Processing & gathering revenues	**(1,168)**	**-**	**(1,168)**	(2,693)	-	(2,693)
Net production & operating expense[1]	**$ 11,567**	**$ 6,299**	**$ 17,866**	$ 14,010	$ 6,707	$ 20,717
Per sales net production & operating expenses *($/boe)*[1]	**$ 15.83**	**$ 32.51**	**$ 19.32**	$ 17.04	$ 24.91	$ 18.98
Per sales production & operating expenses *($/boe)*	**$ 17.43**	**$ 32.51**	**$ 20.59**	$ 20.31	$ 24.91	$ 21.45

Year ended December 31			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating expense	**$ 54,382**	**$ 19,880**	**$ 74,262**	$ 67,769	$ 17,810	$ 85,579
Less:						
Processing & gathering revenues	**(7,205)**	**-**	**(7,205)**	(7,922)	-	(7,922)
Net production & operating expense[1]	**$ 47,177**	**$ 19,880**	**$ 67,057**	$ 59,847	$ 17,810	$ 77,657
Per sales net production & operating expenses *($/boe)*[1]	**$ 15.69**	**$ 28.71**	**$ 18.13**	$ 16.10	$ 24.43	$ 17.46
Per sales production & operating expenses *($/boe)*	**$ 18.09**	**$ 28.71**	**$ 20.07**	$ 18.23	$ 24.43	$ 19.24

(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.

Consistent with a decrease in sales volumes during the fourth quarter and year ended, our production and operating expense of $19.0 million and $74.3 million, respectively, decreased relative to the same periods of 2012.

Similarly, in our Canadian segment, $12.7 million and $54.4 million of production and operating expense for the fourth quarter and reported year, respectively, decreased relative to the same periods of 2012. Again, these decreases resulted from lower sales volumes. Contributing to our lower sales volumes were our Canadian property dispositions during 2012 and 2013, which included the disposition of some of our processing facilities resulting in decreases in our processing and gathering revenues. These property dispositions decreased our non-operated sales volumes which, generally, incurred higher operating costs per boe. When combined with our continued focus on improving our Canadian operating cost structure through various process changes and cost saving initiatives, our operating costs on a boe basis have decreased in the current reporting periods relative to the same periods during 2012. However, despite decreases on a boe basis, 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.

In Tunisia, during the reported year, increased costs for equipment rentals, a workover of our TT12 well, and the strengthening US dollar increased our total production and operating expenses, as well as on a boe basis. We expect our Tunisian BBT operating costs per boe to decrease from our fourth quarter rate by 25 to 30 percent beginning in 2014 as production volumes increase from our commenced six well drilling program and again during the latter half of 2014 when our planned early production facility is scheduled to come on stream. This will in turn lower our existing equipment rental and water hauling expenses. During 2014, we also expect to achieve lower operating costs per boe as a result of a newly negotiated oil trucking contract.

General & Administrative ("G&A") Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	2013	2012	2013	2012
G&A expense	**$ 3,923**	$ 4,313	**$ 12,611**	$ 16,416
Add back/(deduct):				
Share-based compensation	**(233)**	312	**(1,328)**	(2,277)
Provision for bad debts	**(1,089)**	-	**(1,793)**	-
Amortization of deferred lease liability	**264**	264	**1,056**	1,056
Cash G&A expense[1]	**$ 2,865**	$ 4,890	**$ 10,546**	$ 15,195
Per sales *($/boe)*	**$ 3.10**	$ 4.48	**$ 2.85**	$ 3.42

(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 current reporting periods decreased as compared to the same periods of 2012. This was due to an increase in the portion of Tunisian staffing costs that we capitalized to exploration or development assets in combination with our decision in November 2012 to reduce our Canadian office staffing levels in conjunction with the 2011 and 2012 Canadian non-core property disposition program. Also contributing to the G&A decrease was a lower share-based compensation expense. This decrease resulted from higher recoveries on forfeited unvested options mostly related to the reduction in our Canadian staffing levels and less fair value remaining to expense on unvested outstanding options. Partially offsetting these decreases in G&A expense was higher bad debt expenses associated with certain joint venture partners. We will continue to pursue collection, but given efforts to date, it was appropriate to report the credit risk associated with these receivables.

Netbacks

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

Three months ended December 31			2013			2012
Per sales (*$/boe*)	Canada[2]	Tunisia	Total	Canada[2]	Tunisia	Total
Realized sales price	**$ 39.09**	**$ 112.44**	**$ 54.46**	$ 33.07	$ 106.99	$ 51.30
Less:						
Royalties	**(4.80)**	**(3.90)**	**(4.61)**	(0.15)	(2.13)	(0.64)
Net production expense[3]	**(15.83)**	**(32.51)**	**(19.32)**	(17.04)	(24.91)	(18.98)
Cash G&A [4]	**(3.47)**	**(1.69)**	**(3.10)**	(4.72)	(3.75)	(4.48)
Netback [1]	**$ 14.99**	**$ 74.34**	**$ 27.43**	$ 11.16	$ 76.20	$ 27.20

Year ended December 31			2013			2012
Per sales (*$/boe*)	Canada[2]	Tunisia	Total	Canada[2]	Tunisia	Total
Realized sales price	**$ 38.13**	**$ 107.74**	**$ 51.16**	$ 30.74	$ 109.05	$ 43.58
Less:						
Royalties	**(4.39)**	**(3.06)**	**(4.14)**	(2.68)	(2.78)	(2.70)
Net production expense[3]	**(15.69)**	**(28.71)**	**(18.13)**	(16.10)	(24.43)	(17.46)
Cash G&A [4]	**(2.75)**	**(3.33)**	**(2.85)**	(3.06)	(5.22)	(3.42)
Netback [1]	**$ 15.30**	**$ 72.64**	**$ 26.04**	$ 8.90	$ 76.62	$ 20.00

(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. 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.

Our netbacks were consistent for the fourth quarter and increased 30% for the reported year, as compared to the same periods of 2012. During the current reporting periods, increases in the Canadian netback of 34% and 72%, respectively, offset the decreases in the Tunisian netback. The current reporting periods' netbacks, on a boe basis, of $27.43 and $26.04, respectively, were approximately one-half of their average realized sales price, which was an improvement over the same periods in 2012.

The increases in the Canadian 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 crude oil weighted properties. Also contributing to the increase was the change in our commodity portfolio from last year's crude oil weighted acquisition and dry natural gas dispositions as reported since 2011. For the fourth quarter, our Canadian crude oil sales volumes as a percentage of this segment's total production increased to 23%, as compared to 17% in the same period of 2012. 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 and this resulted in an increase in netbacks, despite generally incurring higher production costs per boe for crude oil production. Offsetting the higher production costs related to an increase in crude oil weighted sales volumes during the fourth quarter, was an increase in the proportion of sales coming from our operated properties. Our focus on improving our Canadian operating cost structure through various process changes and cost saving initiatives, helps us realize lower net production costs per boe on production from our operated properties than we do from our non-operated properties. This increase in the proportion of operated sales volumes mostly resulted from our 2012 and 2013 dispositions of non-core properties. In addition, the current reporting periods' Canadian netbacks were positively affected by higher natural gas pricing and lower cash G&A per boe. The Canadian netbacks include cash G&A costs related to our corporate office of $2.38 and $1.73 per boe for the current reporting periods.

Our Tunisian segment's netbacks, as reported in Canadian dollars, for the current reporting periods decreased relative to the same periods of 2012 despite a relative strengthening of the US dollar. On a US dollar and boe basis, lower average sales prices, as consistent with lower Brent benchmarks, combined with higher royalties and higher net production expenses resulting in the decrease of our Tunisian netbacks during the current reporting periods. Furthermore, on a US dollar and boe basis, the increases in our Tunisian royalties resulted from increases in the portion of sales from our royalty paying Adam Concession whereas the increases in our net production expenses resulted from higher costs for rental equipment, water hauling and water disposal on our BBT Concession.

Exploration and Evaluation Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2013**	2012	**2013**	2012
Total	**$ 1,855**	$ 2,164	**$ 11,435**	$ 9,566

Exploration and evaluation expense for the reported year of $11.4 million was higher compared to the same period during 2012. This increase was mostly related to our exploration activities that did not result in discoveries of commercially viable reserves. During the reported year, the costs outlined below, related to the following exploration activities were charged to exploration and evaluation expense:

- We drilled and cased our El Bell exploration well on the onshore Tunisian Sud Remada Permit at a cost of $3.9 million, excluding an estimated decommissioning obligation of $0.2 million, but then suspended this well when no economical petroleum or natural gas reserves were identified in its target zone.
- A $1.1 million completion operation was attempted on our TT4 well on the BBT Concession to access a lower non-productive interval but the objective of this operation was not met.
- We evaluated the recoverability of a Canadian exploration well's costs prior to transferring these costs to D&P Assets, at which time it was determined that the drilling and completion cost incurred was higher than the associated proved plus probable discounted reserves by $0.8 million.
- We completed our evaluation and determined that a Canadian exploration well drilled during 2012 at a cost of $1.4 million was unsuccessful for petroleum or natural gas reserves.

In comparison during 2012, our exploratory drilling program at our BJA-2 wellsite, located on our Tunisian onshore Sud Remada permit, along with the Nessma non-operated well near our Adam Concession, were both unsuccessful for petroleum or natural gas reserves, which resulted in directly charging $3.6 million to exploration and evaluation expense, excluding decommissioning obligation of $0.2 million.

In addition to the above, the remaining $4.0 million and $5.8 million of costs included in exploration and evaluation expense for the reported year and 2012, respectively, were mostly comprised of Canadian and Tunisian pre-licensing evaluation, exploratory lease rental and geological and geophysical costs.

Risk Management Contract Losses (Gains)

	Three months ended December 31		Year ended December 31	
($ thousands)	**2013**	2012	**2013**	2012
Realized loss (gain) on derivative contracts	**$ 77**	$ (591)	**$ (618)**	$ (914)
Unrealized loss (gain) on derivative contracts	**2,009**	(2,055)	**1,572**	(3,029)
Total	**$ 2,086**	$ (2,646)	**$ 954**	$ (3,943)

We use commodity price risk management contracts to reduce our exposure to fluctuations in commodity prices. We present the fair value of each derivative contract by counterparty on the 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. At December 31, 2012, there were no outstanding swaps and collar commodity price contracts or swap option as we had settled all these contracts during the fourth quarter of 2012.

For the reported year, we realized gains on our AECO swap natural gas contracts as the AECO benchmark averaged below the fixed price of the contracts. Inversely, during the latter part of the fourth quarter, the average AECO benchmark increased above the contract fixed price resulting in us reporting a realized derivative loss on these contracts, which expired during the fourth quarter of 2013. If we had included these settlements in our natural gas revenues, we would have reported a lower adjusted fourth quarter natural gas price of $3.97 per mcf as compared to our reported price of $3.99 per mcf and a higher adjusted reported year natural gas price of $3.76 per mcf as compared to our reported price of $3.70 per mcf. Our Brent benchmark indexed collar contract resulted in only a nominal realized loss during the reporting year.

Our unrealized losses for the current reporting periods resulted from our AECO, WTI and Brent benchmarked indexed derivative contracts as outstanding on December 31, 2013. Since we initially acquired these contracts throughout 2013, the forward benchmark prices have increased.

Net Financing Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2013**	2012	**2013**	2012
Interest on bank debt	**$ 482**	$ 1,076	**$ 4,434**	$ 4,500
Interest earned	**(5)**	(279)	**(370)**	(286)
Finance charges and fees	**583**	71	**817**	700
Amortization of deferred financing costs	**213**	-	**679**	-
Accretion of decommissioning obligation	**658**	699	**2,724**	2,853
Total	**$ 1,931**	$ 1,567	**$ 8,284**	$ 7,767

The decrease in our interest on bank debt for the fourth quarter, as compared to the same period of 2012, resulted from lower average outstanding long-term debt. However, our reported year's interest on bank debt was comparable to 2012 as the higher average interest rates resulting from the terms of a new Canadian facility agreement that was entered into on December 11, 2012 mostly offset our lower average outstanding long-term debt. Since the beginning of 2012, we have made principal repayments of $59.0 million. For the reported year, the effective interest rate was approximately 5.0%, compared to a blended rate on our two Canadian facilities of 4.4% during 2012.

Standby fees, as included in finance charges and fees, increased during the current reporting periods, as compared to the same periods in 2012, with the signing of a new international credit facility entered into on March 15, 2013 and discussed under the "Credit Facilities" section of this MD&A. We incurred most of the reported $2.8 million in deferred financing fees upon signing of this facility and are amortizing these costs over the facility's term of five years.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2013**	2012	**2013**	2012
Canada	**$ 10,902**	$ 17,503	**$ 50,199**	$ 75,540
Tunisia	**7,190**	9,123	**23,871**	22,995
Total	**$ 18,092**	$ 26,626	**$ 74,070**	$ 98,535
Per sales *($/boe)*	**$ 19.57**	$ 24.39	**$ 20.02**	$ 22.16

DD&A expense in our Canadian segment for the current reporting periods decreased from the same periods of 2012 due to lower Canadian sales volumes resulting from our 2012 and 2013 non-core property disposition program, as well as the lower carrying amount of our development and production assets, resulting from the reported impairment during 2012 on our Canadian producing properties. In addition, as the majority of our Canadian exploratory assets that relate to undeveloped lands as acquired during a 2010 corporate transaction were fully amortized as of 2012, we are now reporting a significant decrease in the amortization expense of our exploration assets during the current reporting periods as compared to the same periods of 2012. These decreases in net carrying values of our exploration and development assets, as explained above, has also resulted in a lower Canadian DD&A expense on a boe basis.

In our Tunisian segment, DD&A expense during the fourth quarter decreased as a result of both lower sales volumes and a lower DD&A rate per boe. As discussed, the lower Tunisian sales volumes mostly resulted from a delay in our drilling program. The lower DD&A rate is due to the recognition of an increase in our BBT Concession's proved plus probable reserves resulting from our previous drilling campaign as conducted during the first half of 2013. For the reported year, the effect of the lower sales volumes was more than offset by the strengthening US dollar and, on average, a higher DD&A rate, resulting in an increase in 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

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2013**	2012	**2013**	2012
Canada	**$ 3,500**	$ 55,500	**$ 3,500**	$ 82,000
Tunisia	**32,000**	-	**32,000**	-
Total	**$ 35,500**	$ 55,500	**$ 35,500**	$ 82,000
Per sales *($/boe)*	**$ 38.40**	$ 50.84	**$ 9.60**	$ 18.44

Impairment is recognized when an asset or group of assets' carrying amounts exceed their recoverable value defined as the higher of the value in use or fair value less cost to sell. Any asset impairment is recoverable to its original carrying amount less any associated DD&A should there be indicators that the recoverable amount of the asset or group of assets has increased in value since the time of recognizing the initial impairment.

For the reported year, we recognized an impairment charge of $32.0 million on the Tunisian segment's non-producing offshore CGU. This was as a result of our decision to further evaluate the development options for this CGU, the withdrawal of a potential partner and our election to change the classification of this CGU's proved plus probable reserves to a contingent resource. We assessed this CGU's recoverable value based on a measure of its contingent resource using relative fair value third party market transactions for offshore North African early stage development projects with contingent resources. Given the uniqueness of such a project, third party market transactions were not always directly comparable resulting in significant measurement uncertainty. This uncertainty could result in this Tunisian offshore CGU's future realized recoverable amount being significantly below or above management's evaluation of its fair market value.

At December 31, 2013, we determined that there were no indications of impairment for our Tunisian onshore CGU that would warrant testing for impairment; however there were triggers indicating impairment on our Canadian CGUs. These triggers partially result from our reporting of $82.0 million in impairment expense on the Canadian CGUs during 2012, as then triggered through a reduction in forward Canadian petroleum and natural gas prices as listed by McDaniel & Associates Consultants Ltd. Upon reporting this impairment expense, each Canadian CGU's carrying value approximated its recoverable value. This situation created sensitivity to any changes in the recoverable values of our Canadian CGUs when measured at December 31, 2013, relative to the same measure as previously reported. Observed triggers that indicated impairment of our Canadian CGUs included a decrease in the long term forward Canadian natural gas prices as at December 31, 2013, as listed by McDaniel & Associates Consultants Ltd., relative to those estimated at December 31, 2012, and changes in recoverable value from the continued disposition of Canadian producing assets. Each Canadian CGU's impairment test was based on proved plus probable reserves, used an average Canadian CGU discount rate of 10 percent and forward commodity price estimates. Our testing of each Canadian CGU's recoverable value relative to its carrying value revealed an impairment charge of $3.5 million in one non-core CGU and did not reveal any recovery of prior periods' impairment on the remaining CGUs.

A five percent decrease in the forward commodity price estimate, as determined for each Canadian CGU, would have resulted in an additional impairment charge totaling approximately $11.0 million. The impairment tests as carried out at December 31, 2013 and 2012 were based on the following price estimates:

	Edmonton Light Crude Oil ($/bbl)[(1)(2)]		AECO Gas ($/mmbtu)[(1)(3)]	
As at December 31	**2013**	**2012**	**2013**	**2012**
2014	**$ 95.00**	$ 90.50	**$ 4.00**	$ 3.85
2015	**$ 96.50**	$ 92.60	**$ 4.25**	$ 4.35
2016	**$ 97.50**	$ 94.50	**$ 4.55**	$ 4.70
2017	**$ 98.00**	$ 96.40	**$ 4.75**	$ 5.10
2018	**$ 98.30**	$ 98.30	**$ 5.00**	$ 5.45
Thereafter	**2%/yr**	2%/yr	**2%/yr**	2%/yr

(1) Source: McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2013 and 2014.

(2) Central market point for Canadian crude oil.

(3) Central market point for Canadian natural gas.

Gains on Disposition of Properties

During the reported year, we completed the sale of several petroleum and natural gas properties mostly located throughout Alberta, Canada. Aggregate proceeds were $21.0 million (2012 – $106.3 million) when combined with the final statements of operating adjustments on prior period petroleum and natural gas property sales. The carrying amount of these properties, including the disposed decommissioning obligation, was less than the sales proceeds received resulting in a gain of $12.9 million for the reported year compared to $22.5 million during 2012.

Income Tax Expense (Recovery)

	Three months ended December 31		Year ended December 31	
($ thousands)	**2013**	**2012**	**2013**	**2012**
Current income tax expense	**$ 3,549**	$ 1,534	**$ 7,638**	$ 6,193
Deferred income tax expense (recovery)	**28**	-	**(1,210)**	622
Total	**$ 3,578**	$ 1,534	**$ 6,428**	$ 6,815

Current income taxes, mostly relating to our Adam Concession located onshore Tunisia, increased in the current reporting periods as compared to the same periods of 2012. This increase was due to higher crude oil revenues realized from our Adam Concession. During the fourth quarter, we adjusted our estimate of previously deducted exploration costs.

We had a deferred income tax recovery of $1.2 million for the reported year 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 Loss and Comprehensive Loss

	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	2013	2012	2013	2012
Net loss	**$ (39,002)**	$ (36,708)	**$ (26,700)**	$ (91,028)
Per share – basic and diluted *($/share)*	**(0.18)**	(0.17)	**(0.13)**	(0.42)
Comprehensive loss	**$ (34,172)**	$ (35,607)	**$ (18,174)**	$ (93,386)
Per share – basic and diluted *($/share)*	**(0.16)**	(0.17)	**(0.09)**	(0.44)
Weighted average shares outstanding – basic and diluted *(thousands)*	**214,188**	214,188	**214,188**	214,188

Our net loss of $39.0 million in the fourth quarter slightly increased relative to the same quarter of 2012, while our net loss of $26.7 million for the reporting year decreased relative to 2012. For the reported year, this decrease was mostly due to a lower impairment charge of $35.5 million, mostly related to our Tunisian segment's offshore CGU, as compared to $82.0 million as reported against our Canadian CGUs. A lower DD&A expense and the benefit from the realization of the disposition proceeds on a joint arrangement (see "Joint Arrangement") also positively affected our net loss.

For the fourth quarter, as compared to the same period in 2012, the increase in net loss was mostly due to lower Tunisian sales volumes, derivative contract losses, and the absence of the 2012 reported $16.8 million gain on disposition of assets. This fourth quarter increase in net loss was partially offset by a lower impairment charge as compared to $55.0 million in the same quarter of 2012.

Comprehensive losses, which include our net losses and foreign currency translation gains or losses on our Tunisian operations, decreased for the current reporting periods as compared to the same periods in 2012. These decreases in comprehensive losses reflect foreign currency translation gains on marking to market our Tunisian US dollar denominated net assets due to the relative weakening of the Canadian dollar.

Capital Resources, Capital Expenditures and Liquidity

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

Cash flow for the reported year, cash on deposit, in addition to proceeds from the disposition of Canadian non-core properties, financed the investment in capital, exploration and evaluation expenditures, debt principal repayments, decommissioning expenditures and an increase in non-cash working capital. During the reported year, we completed the sale of Canadian non-core properties with associated volumes totalling approximately 580 boe per day.

Cash Flow

	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	2013	2012	2013	2012
Cash flow from operations	**$ 30,966**	$ 38,054	**$ 79,633**	$ 83,944
Add back (deduct):				
Change in operating non-cash working capital	**(11,452)**	(9,769)	**1,233**	(8,229)
Deferred disposition proceeds	**-**	-	**3,051**	-
Decommissioning obligation expenditures	**665**	473	**3,105**	2,982
Cash flow(1)	**$ 20,179**	$ 28,758	**$ 87,022**	$ 78,697
Per share – basic and diluted(1)	**$ 0.09**	$ 0.13	**$ 0.41**	$ 0.37
Per sales *($/boe)*(1)	**$ 21.83**	$ 26.34	**$ 23.52**	$ 17.70

(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 for the reported year increased to $87.0 million, an 11% increase, as compared to 2012 due to higher netbacks and a one-time termination of the NZOG Hammamet Pty. Ltd ("NZOG") optional right (see "Joint Arrangement"). Cash flow for the fourth quarter decreased to $20.2 million compared to the same quarter of 2012 despite comparable netbacks and an increase in Canadian crude oil sales volumes. This decrease was due to lower Tunisian sales volumes and their associated netback in addition to higher realized derivative losses.

Credit Facilities

($ thousands)	December 31 2013	December 31 2012
Long-term debt	$ **75,897**	$ 89,137
Less:		
Working capital excluding mark-to-market derivative contracts	**(14,048)**	(16,754)
Net debt[1]	$ **61,849**	$ 72,383

(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.

Our net debt of $61.8 million as at December 31, 2013, decreased relative to $72.4 million as at December 31, 2012 due to our reported year's cash flow and proceeds on property dispositions of $108.0 million exceeding our $96.2 million in capital, exploration and decommissioning expenditures. The carrying value of our long-term debt decreased throughout the reported year resulting from $2.8 million in cash charges paid upon 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 as partially offset by the non-cash amortization for $0.7 million of these deferred financing fees. During the reported year, we also made a repayment of $11.0 million of outstanding long-term debt. The deferred financing costs and long-term debt repayment, which lowered the carrying amount of our long-term debt, were also included in the change in our working capital.

At December 31, 2013 and 2012, 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 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 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 (December 31, 2012 – $89.5 million and $0.4 million respectively), resulted in available credit on this facility of $36.1 million (December 31, 2012 – $25.1 million).

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, US Base rate, US 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 December 31, 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. At December 31, 2013, the availability of this facility was US$46.5 million as subject to a semi-annual review and redetermination. At December 31, 2013, we had no outstanding drawings against the International Credit Facility. Effective January 1, 2014, our available borrowing base was reduced to US$23.8 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. 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 $2.6 million remained at December 31, 2013 and will be amortized through to the anticipated expiry of each facility's agreement.

Capital Expenditures

Three months ended December 31				2013				2012
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	$ -	$ -	$ -	$ -	$ 390	$ -	$ -	$ 390
Drilling and completions	5,943	4,162	-	10,105	3,848	11,991	-	15,839
Facilities and equipment	3,638	147	-	3,785	1,658	1,503	-	3,161
Field expenditures	9,581	4,309	-	13,890	5,896	13,494	-	19,390
Capitalized G&A	272	-	-	272	364	814	-	1,178
Furniture and equipment	-	-	-	-	-	-	7	7
Property acquisitions(1)	-	-	-	-	29,881	-	-	29,881
Total	$ 9,853	$ 4,309	$ -	$ 14,162	$ 36,141	$ 14,308	$ 7	$ 50,456
Proceeds from dispositions	$ 1,281	$ -	$ -	$ 1,281	$ 33,087	$ -	$ -	$ 33,087

Year ended December 31				2013				2012
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	$ 3,255	$ -	$ -	$ 3,255	$ 1,208	$ -	$ -	$ 1,208
Drilling and completions	27,397	27,539	-	54,936	18,195	42,797	-	60,992
Facilities and equipment	10,798	8,744	-	19,542	7,566	5,776	-	13,342
Field expenditures	41,450	36,283	-	77,733	26,969	48,573	-	75,542
Capitalized G&A	1,101	4,302	-	5,403	1,624	2,465	-	4,089
Furniture and equipment	-	-	92	92	-	-	69	69
Property acquisitions(1)	-	-	-	-	29,957	-	-	29,957
Total	$ 42,551	$ 40,585	$ 92	$ 83,228	$ 58,550	$ 51,038	$ 69	$ 109,657
Proceeds from dispositions	$ 20,984	$ -	$ -	$ 20,984	$ 106,287	$ -	$ -	$ 106,287

(1) Includes business combination of $29.9 million in 2012.

Wells Drilled

A summary of our drilling activities for the fourth quarter and year ended 2013 is as follows:

Three months ended December 31, 2013	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Development oil wells	-	-	5.00	1.65	5.00	1.65
Total	-	-	5.00	1.65	5.00	1.65

Year ended December 31, 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	11.00	6.02	15.00	8.65
Dry wells	1.00	0.86	-	-	1.00	0.86
Total	5.00	3.49	15.00	8.26	20.00	11.75

Canada Capital Expenditures

Our Canadian activity in the fourth quarter saw the commencement of an operated four (3.5 net) well drilling program at Albright, and the completion of a non-operated four (1.15 net) well drilling program at Karr. Dunvegan oil is the target on both of these properties in our Grande Prairie core area. Preliminary work was finalized on two separate Montney drilling prospects during the fourth quarter, with horizontal wells to be drilled during the first quarter of 2014.

At Albright, one (0.5 net) horizontal well was drilled during the fourth quarter, and was completed and brought on stream in late January of 2014. The rig is currently drilling the fourth horizontal well in the program. Three of these four wells were completed and brought on stream during the first quarter of 2014. Once the fourth well is completed, it will bring our total to ten (8.0 net) new horizontal wells that have been drilled on the property since it was acquired in December of 2012. The initial seven (5.0 net) new wells are currently producing 1,031 boe per day (833 boe per day net) at 81% oil, and are incremental to the 280 boe per day of the original acquisition. We have at least two (1.5 net) additional wells budgeted at Albright for 2014, with up to eighteen (16 net) locations identified.

The majority of our activity during the fourth quarter was on our Karr property, where we participated in the drilling of four (1.15 net) new horizontal wells, bringing the total number of wells on this property to nine (2.9 net). All four of the new wells have been completed and three were brought on production in the first quarter of 2014. The operator has continued to reduce costs on the latest wells and early indications are that production rates will meet or exceed internal expectations. We anticipate net production from this property will exceed 700 boe per day (greater than 80% oil) during the first quarter of 2014. There are two (0.63 net) more wells budgeted at Karr in 2014, with up to 19 (6.7 net) additional locations identified.

During the fourth quarter, we finalized our preparations to drill two separate Montney prospects. One (0.75 net) horizontal Montney well was drilled in January 2014 at Birley/Umbach in north eastern British Columbia, targeting liquids-rich natural gas. The well will be completed and tested in the second quarter of 2014. Success on this prospect could lead to a large-scale development of our 35 section Montney land block. We also drilled one (0.37 net) horizontal Montney well in the Karr/Gold Creek area in January 2014, targeting oil and liquids-rich natural gas. This is also an active Montney fairway where we own a significant amount of prospective acreage. One more Montney well is budgeted for 2014 in the Gold Creek area.

Additional opportunities currently budgeted for 2014 include horizontal drilling locations in the Grande Prairie core area targeting Doe Creek oil, Charlie Lake oil and Halfway oil.

Tunisia Capital Expenditures

At our BBT Concession, capital activity in the fourth quarter of 2013 included preparing the drilling site and spudding our TT15 well (0.86 net), the optimization of the TT8 well through the running of a velocity string and the preparation required to convert the TT12 horizontal well to a water injector. The TT15 well was spud in late December and will be the first of a six well (5.16 net) vertical program. Each well is targeting the Lower Jeffara/Upper BBT target interval and is budgeted at $4.0 million to drill and complete. Civil construction on the second location TT28 was started in late December 2013.

The TT8 well had a velocity string installed in December to improve the well performance and stabilize the flow rate. The velocity string was pulled on the TT12 horizontal well to prepare it for water injection in 2014. Water treatment rental equipment was tested at the TT12 horizontal well location to determine if produced water could be treated to injection standards. The test was successful and a number of changes to optimize the system were identified.

Long lead items such as BBT's 13 kilometer gathering system's pipe and bolted tanks have arrived on location and are racked in the field until the engineering and tendering for the installation is completed, which is expected within the first quarter of 2014. These will be used as part of the construction of a central gathering facility and oil battery which is projected to commence during the first half of 2014.

Planning is underway to drill one (0.05 net) development well during the second half of 2014 on our non-operated Adam Concession and one (0.10 net) exploration well on our non-operated BEK permit.

Rationalization of Non-Core Properties

During the reported year, we completed the sale of several non-core petroleum and natural gas properties located throughout Alberta, Canada, for aggregate net proceeds of $21.0 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, Harmattan and Little Horse. Our production from these and other minor dispositions was approximately 580 boe per day. The funds received for these dispositions were used to partially fund our capital program expenditures of $83.2 million.

Joint Arrangement

During the reported year, NZOG acknowledged that it had given a negative final investment decision ("FID") as defined under the terms of our amended farmout agreement (the "Amended Farmout Agreement") as dated March 19, 2013. This terminated NZOG's optional right to complete its earning and acquisition of an interest in the Tunisian Cosmos Concession per the terms of the Amended Farmout Agreement. Given the termination of this optional right, during 2013 we reported the initial US$3.0 million deferred disposition proceeds on joint arrangement we received from NZOG as realized through foreign exchange & other (gains) and losses.

Decommissioning Obligation

At December 31, 2013, we had decommissioning obligations of $90.4 million (December 31, 2012 – $110.5 million) for the future abandonment and reclamation of our properties. At December 31, 2013, an increase in the risk-free rate used in the calculation of the present value of our obligation resulted in a decrease to the estimated decommissioning obligation of $11.7 million as at December 31, 2013 (2012 – increase of $29.2 million). In addition, the decommissioning obligation also decreased as a result of non-core property dispositions, which removed $9.5 million of obligations in addition to $3.1 million of abandonment and reclamation expenditures.

As at December 31, 2013 and 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. As at December 31, 2013, a risk-free interest rate of between 1.1% and 3.2% (2012 – 2.5%) was used in order to calculate the present value the obligation.

The recognized accretion charges reflect the increase in the obligation associated with the passage of time. For the reported year, an accretion charge of $2.7 million was comparable to the charge of $2.9 million reported during the same period in 2012. During the reported year, additions to the decommissioning obligation of $1.1 million were due to the reported year's drilling activities (2012 – $1.0 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:

	December 31 2013	December 31 2012
Common shares outstanding	**214,187,681**	214,187,681
Share options	**14,319,699**	13,860,866
Share purchase warrants	**-**	1,279,000
Fully diluted common shares	**228,507,380**	229,327,547
Weighted average common shares – basic and diluted	**214,187,681**	214,187,681

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

As at March 24, 2014, we had 214,187,681 common shares and 13,328,449 share options outstanding.

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' policy which determines which commodities are subject to such contracts, the maximum contracted notional production volume, the referenced indexed price and contractual terms.

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 loss as unrealized risk management contract gains or losses. Realized risk management contract gains or losses are recognized in net loss 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. Our management continuously reviews the need to utilize such financing techniques.

As at December 31, 2013, we had the following commodity price contracts with an estimated fair value current liability of $1.6 million:

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

Commitments, Contingencies and Guarantees

At December 31, 2013, we had contractual commitments that require the following minimum future payments without giving effect to any offsetting third party agreements which are anticipated to reduce some of these amounts:

	Year ended December 31					
($ thousands)	2014	2015	2016	2017	2018	Total
Long-term debt and interest	$ 4,454	$ 80,991	$ 529	$ 529	$ 529	$ 87,032
Office leases	1,990	1,630	1,668	1,708	920	7,916
Operating and transportation contracts	5,019	440	125	9	-	5,593
Minimum financial work commitments	-	6,913	-	-	-	6,913
	$ 11,463	**$ 89,974**	**$ 2,322**	**$ 2,246**	**$ 1,449**	**$ 107,454**

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

As at December 31, 2013, Chinook issued letters of credit in the total amount of $0.4 million mostly to secure the services of a Canadian midstream operator. These issued letters of credit reduce the available credit from Chinook's Canadian Revolving Term Credit Facility.

Off Balance Sheet Arrangements

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

Related Party Transactions

We have determined that the key management personnel consist of our officers and directors. In addition to the salaries and directors fees paid to our officers and directors respectively, our officers and directors participate in our share option plan. The officers' salary and directors' fees paid, in addition to share-based compensation and other benefits, included in general and administrative expenses relating to key management personnel for 2013 was $2.7 million and $1.0 million, respectively (2012 – $2.9 million and $1.9 million, respectively).

A significant shareholder of ours has appointed AIMCo as its investment manager. We in turn provide certain services to nominees of AIMCo pursuant to an administrative services and cost sharing agreement. These services include managing the working interests of AIMCo's nominees as held in a limited partnership. The calculated fee for these services from AIMCo's nominees during the reporting year was $4.0 million (2012 – $3.5 million), as applied against our G&A expense, of which $0.1 million as at December 31, 2013, was included in accounts receivable (December 31, 2012 – $1.9 million). At December 31, 2013, a net receivable of $0.3 million remained related to the ongoing joint operations of producing and non-producing oil and natural gas properties (at December 31, 2012, a net payable of $10.8 million).

All related party transactions are in the normal course of business and have been valued at normal commercial terms.

Outlook

We are maintaining the guidance for 2014 that was initially announced in the news release of December 19, 2013, with only an improvement to our year end net debt.

($ millions, except boe/d)	Consolidated	International	Canada
Production (boe/d)	9,500 - 10,250	1,850 - 2,130	7,650 - 8,120
Cash flow	$82 - $90	$42 - $46	$40 - $44
Capital expenditures	$85	$36	$49
Net debt	$60	-	$60
Maximum available credit	$139	US $23.8	$115

For 2014 we are focused on the continued development of our properties at Karr, Albright and the BBT Concession while pursuing new resource opportunities over a large undeveloped Western Canadian land base that would provide meaningful and economic scale to our shareholders that would be supported by a fully financed cash flow based budget and further supported by a healthy balance sheet.

Also in 2014 we are continuing with our 2013 initiative reviewing 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 the market valuation of Chinook as a hybrid company relative to our domestic peers. We caution that there are no assurances or guarantees that such process will result in a transaction or, if a transaction is undertaken, the terms or timing of such a transaction.

2014 will be an exciting and pivotal year at Chinook and we would like to thank our employees and Board of Directors for their ongoing commitment and our shareholders for their continued support. We look forward to providing you with updates of our success throughout 2014.

Selected Annual Information

Summarized information by year for the three years ended December 31, 2013, appears below:

Year ended December 31 *($ thousands, except per share amounts)*	2013	2012	2011
Petroleum and natural gas revenue, net of royalties	**$ 173,918**	$ 181,802	$ 202,763
Net loss[(2)]	**$ (26,700)**	$ (91,028)	$ (63,752)
Per share – basic and diluted *($/share)*	**$ (0.13)**	$ (0.42)	$ (0.30)
Total assets[(2)]	**$ 555,341**	$ 622,476	$ 745,403
Long-term financial liabilities[(1)]	**$ 174,984**	$ 209,451	$ 243,072

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

(2) Includes $43.0 million, $82.0 million and $35.5 million in impairment charges for the years ended December 31, 2011, 2012 and 2013, respectively.

Our decreased petroleum and natural gas revenue, net of royalties, over these three years reflect lower Canadian production volumes resulting from our ongoing Canadian non-core property disposition program, as partially offset through increased crude oil production volumes during 2012 from our Tunisian operations. Partially offsetting the effect of lower production volumes on our revenues, net of royalties, was a 2013 increase in our average commodities sales price. Our net losses for the years ended 2011, 2012 and 2013 were negatively impacted by $43.0 million, $82.0 million and $3.5 million, respectively, of impairment charges against our Canadian CGUs resulting from decreases in the forward curve of North American natural gas prices attributed to an abundance of natural gas inventory resulting from rapid North American shale-gas development. Our net loss for the year ended 2013 was also negatively impacted by an additional $32.0 million impairment charge against our offshore Tunisian CGU that resulted from our decision to reclassify our reserves to a contingent resource as we continue to evaluate the development options for this project. These impairment charges, in addition to our non-core property disposition program, were greater than our capital expenditures resulting in a decrease in the carrying value of our total assets in each consecutive year. Decreases in long-term financial liabilities from the year ended 2011 through to the year ended 2013 resulted primarily from net long-term debt repayments of $48.0 million and $11.0 million during the years ended 2012 and 2013, respectively. Further reducing the long-term financial liabilities during the reported year was a decrease in the decommissioning obligation resulting from our Canadian disposition program and a decrease in this liability's estimate.

Please refer to "Operations" and other sections of this MD&A for detailed discussions on variations during the comparative year ended and to our previously annual management's discussion and analysis for changes in the prior year.

Quarterly Information

Summarized information by quarter for the two years ended December 31, 2013, appears below:

	Dec. 31 2013	Sept. 30 2013	Jun. 30 2013	Mar. 31 2013	Dec. 31 2012	Sept. 30 2012	Jun. 30 2012	Mar. 31 2012
OPERATIONS								
Production								
Oil *(bbl/d)*	**3,356**	3,456	3,298	3,565	4,035	3,516	3,195	3,819
Natural gas liquids *(bbl/d)*	**722**	753	874	1,005	1,003	1,141	1,122	1,202
Natural gas *(mcf/d)*	**33,612**	35,820	34,458	37,736	39,585	43,839	43,387	51,445
Average daily production *(boe/d)*	**9,680**	10,180	9,916	10,860	11,636	11,964	11,548	13,596
Sales								
Oil *(bbl/d)*	**3,725**	3,558	3,588	2,710	4,264	3,929	2,385	3,846
Natural gas liquids *(bbl/d)*	**722**	753	874	1,005	1,003	1,141	1,122	1,202
Natural gas *(mcf/d)*	**33,612**	35,820	34,458	37,736	39,584	43,839	43,387	51,445
Average daily sales *(boe/d)*	**10,049**	10,282	10,205	10,006	11,865	12,377	10,738	13,623
Sales Prices								
Average oil price *($/bbl)*	**$ 98.57**	$ 104.46	$ 98.07	$ 95.03	$ 97.72	$ 95.61	$ 89.11	$ 101.06
Average natural gas liquids price *($/bbl)*	**$ 63.74**	$ 62.36	$ 55.06	$ 58.85	$ 57.71	$ 56.42	$ 55.46	$ 70.66
Average natural gas price *($/mcf)*	**$ 3.99**	$ 3.00	$ 4.13	$ 3.72	$ 3.39	$ 2.57	$ 2.08	$ 2.27
Netback(1)								
Average commodity pricing *($/boe)*	**$ 54.46**	$ 51.17	$ 53.13	$ 45.70	$ 51.30	$ 44.67	$ 33.97	$ 43.35
Royalties *($/boe)*	**$ (4.61)**	$ (3.30)	$ (4.88)	$ (3.79)	$ (0.64)	$ (2.50)	$ (3.29)	$ (4.22)
Net production expenses *($/boe)*(1)	**$ (19.32)**	$ (19.28)	$ (17.31)	$ (16.52)	$ (18.98)	$ (18.38)	$ (14.46)	$ (17.65)
Cash G&A *($/boe)*(1)	**$ (3.10)**	$ (2.46)	$ (3.02)	$ (2.83)	$ (4.48)	$ (2.54)	$ (3.74)	$ (3.03)
Netback *($/boe)*(1)	**$ 27.43**	$ 26.13	$ 27.92	$ 22.56	$ 27.20	$ 21.25	$ 12.48	$ 18.45
Wells Drilled (net)								
Oil	**1.65**	3.86	1.77	3.61	2.96	1.11	0.86	3.16
Gas	**-**	-	-	-	-	-	-	1.00
Dry	**-**	-	0.86	-	-	-	0.86	0.10
Total wells drilled (net)	**1.65**	3.86	2.63	3.61	2.96	1.11	1.72	4.26
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties(2)	**$ 46,088**	$ 45,285	$ 44,805	$ 37,740	$ 55,303	$ 48,012	$ 29,979	$ 48,509
Cash flow(1)(2)	**$ 20,179**	$ 23,146	$ 22,179	$ 21,518	$ 28,757	$ 20,935	$ 9,830	$ 19,174
Per share – basic and diluted *($/share)*	**$ 0.09**	$ 0.11	$ 0.10	$ 0.10	$ 0.13	$ 0.10	$ 0.05	$ 0.09
Net income (loss)(2)(3)	**$ (39,002)**	$ 3,812	$ 3,990	$ 4,500	$ (36,708)	$ (12,417)	$ (24,812)	$ (17,091)
Per share – basic and diluted *($/share)*	**$ (0.18)**	$ 0.02	$ 0.02	$ 0.02	$ (0.17)	$ (0.06)	$ (0.12)	$ (0.08)
Capital expenditures	**$ 14,162**	$ 20,961	$ 23,059	$ 25,046	$ 50,456	$ 22,674	$ 13,083	$ 23,446
Net debt(1)	**$ 61,849**	$ 65,105	$ 66,340	$ 64,440	$ 72,383	$ 80,428	$ 77,092	$ 89,182
Total assets	**$ 555,341**	$ 593,192	$ 621,143	$ 617,459	$ 622,476	$ 628,542	$ 637,238	$ 692,023
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, 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 the fourth 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 from the fourth quarter of 2011 until the third quarter of 2013 and increased Canadian crude oil production resulting from a drilling program which began in 2012. 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, 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 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 one of our offshore, non-producing Tunisian CGUs and one of our Canadian development and production CGUs, 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. Since the second quarter of 2012, capital expenditures have generally focused on our Tunisian organic growth, however; since the third quarter of 2013 capital expenditures have shifted to our Canadian drilling and completions programs, as we pursued new oil wells in our Grande Prairie district and saw a reduction in our Tunisian expenditures pending additional governmental approvals.

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

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

Additional Risks Relating to Tunisian Operations

Political and Security Risks

During 2011, Tunisia experienced a period of political unrest and civil disobedience of increasing intensity leading to the resignation of the President of Tunisia. On October 23, 2011, open and free elections were held to elect a committee referred to as the ANC, with the responsibility to write a new constitution. The ANC (Constituent Assembly of Tunisia) is led by a three party coalition with the largest party being the moderate Islamic party Ennahda. The ANC appointed an interim government who were tasked with running the country until the constitution was completed and new parliamentary elections were held. In response to protests that arose following the assassination of a leading opposition politician in January 2013, the governing coalition lead by the Ennahda party appointed several new Ministers who are not politically aligned with any party. A second opposition politician was assassinated on July 25, 2013 which led to calls for the interim government to step down. Protracted discussions ensued with no material progress through to the end of 2013. In January 2014, the governing coalition agreed to step down in favour of a new interim government of non-aligned ministers until the parliamentary elections can be held. The new technocratic government took office on January 29, 2014. This government has been taking a very proactive approach to dealing with terrorism in the country. In January 2014, the ANC voted in favour of the new constitution. The ANC is currently working to update the electoral law. Once this is completed, the date for the election will be announced. It is anticipated that the election will be held prior to the end of 2014. Due to the temporary nature of the current caretaker government, it is possible that delays in receipt of approvals, either regulatory or operational, may cause delays in program delivery beyond what we have forecast.

Tunisia is bordered by both Algeria and Libya. In late 2012, the operating environment in Tunisia became more complicated and necessitated an increase in the required security measures at our operations. However, since early 2013, the incidence of local land issues and hiring demands on us have diminished substantially due in part to our on-going community engagement and investment program. It is possible that the security situation in Tunisia may deteriorate to the point that our operations are materially adversely affected or that we deem it appropriate to suspend our operations in Tunisia.

Our Tunisian oil and natural gas operations are subject to political, economic and other uncertainties. Those uncertainties include: (i) the risk of war, revolution, border disputes, expropriation, renegotiation or modification of existing contracts, import, export, and transportation regulations and tariffs resulting in loss of revenue, property and equipment; (ii) nationalization of assets by the Tunisian government; (iii) taxation policies, including royalty and tax increases and retroactive tax claims; (iv) exchange controls, currency fluctuations and other uncertainties arising out of Tunisian government sovereignty over oil and gas properties; (v) laws and policies of Canada affecting foreign trade, taxation and investment; and (vi) the possibility of being subjected to the jurisdiction of Tunisian courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of the courts of Canada, all of which could adversely affect the outcome of a legal dispute. Political instability in Tunisia could result in a new government or the adoption of new policies, laws or regulations that might exhibit a substantially more hostile attitude toward foreign investment in general or our company in particular. In an extreme case, such change could result in termination of contract rights (including, without cause) and expropriation or nationalization of assets owned by foreign entities. Any such activity could result in significant loss to us. In addition, we may be at a disadvantage in that we may be required to compete against corporations or other entities from countries that are not subject to Canadian laws and regulations, including the *Corruption of Foreign Public Officials Act* (or similar legislation of other jurisdictions, including the United States *Foreign Corrupt Practices Act*).

Furthermore, international oil and natural gas operations in Tunisia involve substantial costs and are subject to certain risks owing to the underdeveloped nature of the oil and natural gas industry in Tunisia. The oil and natural gas industry in Tunisia is not as developed as the oil and natural gas industry in Canada. As a result, drilling and development operations may take longer to complete and may cost more than similar operations in Canada. The availability of technical expertise, specific equipment and supplies is more limited in Tunisia than in Canada. Such factors may subject oil and natural gas operations in Tunisia to economic and operating risks not experienced in Canada.

Requirements for Permits and Licenses

Our operations in Tunisia require licenses, permits and in some cases renewals of existing licenses and permits from the Government of Tunisia (named the Licensing Authority in the Conventions). We believe that we currently hold or have applied for all necessary licenses and permits to carry on the activities, which we are currently conducting under applicable laws and regulations in respect of our properties, and also believe that we are complying in all material respects with the terms of such licenses and permits. However, our ability to obtain, sustain or renew such licenses or permits on acceptable terms is subject to change in regulations and policies and to the discretion of the government.

Under the hydrocarbon law in Tunisia, exploration costs incurred on an exploration permit are eligible for cost recovery against the first concession to be put on production out of the permit. We have made application to have the prior expenditures made on the Hammamet Permit formally recognized by the appropriate Tunisian authorities and credited accordingly. This application was reviewed by the Finance Ministry and we were granted $19.7 million of prior expenditures.

Tunisian Legal System

Tunisia has a less developed legal system than in Canada, which may result in risks such as: (i) effective legal redress in the courts of such jurisdiction, whether in respect of a breach of law or regulation, or, in an ownership dispute, being difficult to obtain; (ii) a higher degree of discretion on the part of governmental authorities; (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations; (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders or resolutions; or (v) relative inexperience of the judiciary and courts in such matters.

In addition, the commitment of local businesspeople, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for businesses. These may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance the joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of government authorities and the effectiveness of an enforcement of such arrangements in Tunisia cannot be assured. As a result of a limited infrastructure present in Tunisia, the land titles systems are not developed to the extent found in many more developed nations. Although we believe that we have good title to our oil and natural gas properties, there is little we can do to control this risk.

Tax Risks Related to Tunisian Operations

We are required to pay tax and royalties on oil and natural gas production from joint venture concessions in Tunisia. Going forward, a change in mix of production between oil and natural gas production or a change in the form of production could have a significant impact on the tax payable by us. In addition, Tunisian tax is calculated on a concession basis and tax losses available for carry forward in one field cannot be offset against taxable profits in other fields. The tax payable going forward in Tunisia could therefore be significantly impacted by which Tunisian fields are profitable and the availability of tax losses to offset those profits.

Exploration, Development and Production Risks

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

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

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

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

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

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

Global Financial Markets

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

Prices, Markets and Marketing

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

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices.

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

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

Market Price of Common Shares

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

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

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including, but not limited to:

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

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

Gathering and Processing Facilities and Pipeline Systems

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

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

Competition

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

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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

Regulatory

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

Royalty Regimes

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

Hydraulic Fracturing

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

Environmental

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

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

Liability Management

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

Climate Change

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

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Substantial Capital Requirements

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

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

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

Additional Funding Requirements

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

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

Credit Facility Arrangements

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

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

Issuance of Debt

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

Hedging

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

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

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

Availability of Drilling Equipment and Access

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

Title to Assets

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

Reserve Estimates

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

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

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

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

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

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

Insurance

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

Control by Principal Shareholder

Her Majesty the Queen in Right of the Province of Alberta (“HMQ”) owns 80,357,142 common shares, representing approximately 37.5% of our current outstanding common shares. Alberta Investment Management Corporation (“AIMCo”), as investment manager to HMQ, maintains investment control and direction over the common shares for the benefit of HMQ. Accordingly, AIMCo will have significant influence over our business and affairs and may have the ability to take shareholder actions irrespective of the vote of any other shareholders, including the ability to prevent certain transactions that it does not believe are in HMQ’s best interest. This significant influence may discourage transactions involving a change of control of our company, including transactions in which our minority shareholders might otherwise receive a premium for the common shares over the then-current market price.

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

Geopolitical Risks

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

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

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

Litigation

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

Aboriginal Claims

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

Breach of Confidentiality

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

Income Taxes

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

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

Seasonality

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

Third Party Credit Risk

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

Conflicts of Interest

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

Reliance on Key Personnel

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

Management Judgment and Estimation Uncertainty

The preparation of financial statements requires management judgments and estimation uncertainty that affect the reported amounts of assets and liabilities, the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting year. Actual results could differ from those estimated. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. Management judgments and the key sources of estimation uncertainty that have a significant risk of causing material adjustment to the carrying amounts of assets and liabilities are discussed below.

Cash Generating Units

The recoverability of development and production asset carrying values was assessed at the Cash Generating Unit ("CGU") level. Determination of what constitutes a CGU is subject to management judgments. The asset composition of a CGU can directly impact the recoverability of the assets included therein.

Recoverability of asset carrying values

When assessing the recoverability of petroleum and natural gas properties, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less cost to sell and value in use.

At December 31, 2013, we assessed for any indicators of potential impairment or related recovery of previously reported impairments. In making this assessment, we used the following information:

a) The net present value of before and after tax cash flows from each of our Canadian and Tunisian segments' CGUs, respectively, for petroleum and natural gas proved plus probable reserves as estimated by our independent reserve evaluators;

b) Evaluation of third party consideration for recent market transactions completed on similar assets to those contained within the relevant CGU; and

c) The fair value of undeveloped land based on estimates provided by our independent land evaluator.

Key input estimates used in the determination of cash flows from petroleum and natural gas reserves include the following:

a) Reserves – assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs, recovery rates or timing of capital expenditures may change the economic status of reserves and may ultimately result in reserves being reclassified.

b) Petroleum and natural gas prices – forward price estimates of the petroleum and natural gas prices are used in the cash flow model. Commodity prices can fluctuate widely due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

c) Discount rates – an approximate industry peer group weighted average cost of capital is used to discount the net present values of cash flows from our Canadian and Tunisian segments CGUs. Changes in the global economic environment could result in significant changes to the discount rates used to calculate the net present value of cash flows.

Depletion of petroleum and natural gas assets

Depletion of petroleum and natural gas assets is determined based on total proved and probable reserve values as well as future development costs as estimated by our external reserve evaluators. Reserve assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being revised.

Decommissioning obligation

The provision for the decommissioning obligation is based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology.

Deferred taxes

Tax interpretations, regulations and legislation are subject to change and as such income taxes are subject to measurement uncertainty. Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

Foreign currency

The determination of our Tunisian operation's functional currency requires assessing several factors, including the dominant currency used in transactions such as the settlement of revenues and operational and capital expenditures, and to a lesser extent financing of this operation.

New Standards and Interpretations Not Yet Adopted

In November 2013, the International Accounting Standards Board ("IASB") issued a new general hedge accounting standard, which forms part of IFRS 9 Financial Instruments (2013) and aligns hedge accounting more closely with risk management. A new mandatory effective date will be determined once the classification and measurement and impairment phases of IFRS 9 are finalized. This new standard does not fundamentally change the types of hedging relationships or the requirement to continually measure and recognize if a hedge is actually ineffective; however it will provide more risk management hedging strategies to qualify for hedge accounting and introduce more judgment to assess the effectiveness of a hedging relationship. Special transitional requirements have been set for the application of the new general hedging model. Currently, we do not apply hedge accounting for our outstanding risk management contracts. Once this new standard is finalized and a new mandatory effective date is set by the IASB, we will then assess the impact of this new standard.

In December 2011, the IASB published amendments to International Accounting Standard ("IAS") 32 "Financial Instruments: Presentation". The effective date for the amendments to IAS 32 is annual periods beginning on or after January 1, 2014. These amendments are to be applied retrospectively. The amendments to IAS 32 clarify that an entity currently has a legally enforceable right to offset the presentation of financial instruments by counterparty if that right is:

- not contingent on a future event; and
- enforceable both in the normal course of business and in the event of default, insolvency or bankruptcy of the entity or the counterparty.

The amendments to IAS 32 also clarify when a settlement mechanism provides for net or gross settlement. We intend to adopt the amendments to IAS 32 in our consolidated financial statements for the annual period beginning January 1, 2014. We do not expect the amendments to have a material impact on our consolidated financial statements.

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 consolidated statements 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 our consolidated financial statements as at December 31, 2013 or 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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of our disclosure controls and procedures at December 31, 2013 and have concluded that our disclosure controls and procedures are effective at December 31, 2013 for the foregoing purposes.

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 December 31, 2013, that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting at December 31, 2013. Our CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of our internal controls over financial reporting at December 31, 2013 and have concluded that our internal controls over financial reporting are effective at December 31, 2013 for the foregoing purposes.

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: 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 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 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 development and exploitation activities, all costs in respect of certain wells being accurately estimated, 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 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, 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, ability 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.