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Management's Discussion and Analysis

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. ("Chinook" or the "Company") for the three and nine months ended September 30, 2012 and 2011 and should be read in conjunction with Chinook's condensed consolidated financial statements and accompanying notes as at and for the three and nine months ended September 30, 2012 and 2011 and consolidated financial statements and accompanying notes as at and for the years ended December 31, 2011 and 2010. This MD&A is based on information available as at November 13, 2012.

The terms "third quarter" and "year to date 2012" or similar terms are used throughout this document and refer to the three and nine month periods ended September 30, 2012, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three and nine month periods ended September 30, 2012. The term "same period of 2011" or similar terms are used throughout this document and refer to the three or nine month periods ended September 30, 2011 depending on the 2012 period under discussion.

Additional Information

Additional information for Chinook, including the Annual Information Form for the year ended December 31, 2011 ("AIF") can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The condensed consolidated financial statements and comparative information for the three and nine months ended September 30, 2012 and 2011 have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The consolidated financial position and results of operations include the accounts of Chinook's direct and indirect subsidiaries all of which are wholly owned. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per share amounts or as otherwise noted. Certain financial measures referred to in this MD&A, such as cash flow, cash flow per share, corporate netbacks, net debt, net production expense, cash G&A, etc., are not prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

Introduction to Chinook

Chinook is a Calgary-based public oil and natural gas exploration and development company with predominately natural gas and liquids reserves in Western Canada and crude oil reserves onshore and offshore in Tunisia, North Africa. Chinook is incorporated under the laws of the Province of Alberta, Canada. Chinook's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "CKE". Chinook's head office and principal address is Suite 700, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

Chinook's continuing operating and reportable segments are as follows:

- **Canada –** includes Chinook's Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in the Peace River and Grande Prairie areas located along the northern portion of the border of the Provinces of British Columbia and Alberta.
- **Tunisia –** includes eight blocks totaling over three million gross acres, offshore in the Gulf of Hammamet within the Pelagian Basin (Cosmos, Yasmin and Hammamet Offshore) and Sud Remada, Bir Ben Tartar, Jenein, Adam and Borj El Khadra Blocks, all onshore properties located within the Ghadames Basin.
- **Corporate –** includes derivative transactions and swap option gains and losses, 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 Operations Highlights

	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
OPERATIONS				
Production				
Oil *(bbl/d)*	**3,516**	3,705	**3,510**	3,578
Natural gas liquids *(bbl/d)*	**1,141**	1,343	**1,155**	1,453
Natural gas *(mcf/d)*	**43,839**	56,364	**46,215**	56,375
Average daily production *(boe/d)*	**11,964**	14,443	**12,367**	14,428
Sales Prices				
Average oil price *($/bbl)*	**$ 95.61**	$ 94.19	**$ 96.15**	$ 91.25
Average natural gas liquids price *($/bbl)*	**$ 56.42**	$ 67.15	**$ 61.03**	$ 64.04
Average natural gas price *($/mcf)*	**$ 2.57**	$ 3.84	**$ 2.31**	$ 3.90
Corporate Netbacks (1)				
Average commodity pricing *($/boe)*	**$ 44.67**	$ 45.63	**$ 41.07**	$ 44.08
Royalties *($/boe)*	**$ (2.50)**	$ (5.24)	**$ (3.37)**	$ (6.96)
Net production expenses *($/boe)* (1)	**$ (18.38)**	$ (20.25)	**$ (16.97)**	$ (16.91)
Cash G&A *($/boe)* (1)	**$ (2.54)**	$ (1.80)	**$ (3.07)**	$ (2.03)
Corporate Netbacks *($/boe)* (1)	**$ 21.25**	$ 18.34	**$ 17.66**	$ 18.18
Wells Drilled *(net)*				
Oil	**1.11**	7.45	**5.13**	12.99
Gas	**-**	0.65	**1.00**	6.71
Dry	**-**	-	**0.96**	-
Total wells drilled *(net)*	**1.11**	8.10	**7.09**	19.70
FINANCIAL *($ thousands, except per share amounts)*				
Petroleum and natural gas revenue, net of royalties	**$ 48,012**	$ 53,920	**$ 126,500**	$ 145,489
Cash flow (1)	**$ 20,935**	$ 22,114	**$ 49,939**	$ 61,054
Per share - basic and diluted *($/share)*	**$ 0.10**	$ 0.10	**$ 0.23**	$ 0.29
Net loss	**$ (12,417)**	$ (3,543)	**$ (54,320)**	$ (5,675)
Per share - basic and diluted *($/share)*	**$ (0.06)**	$ (0.02)	**$ (0.25)**	$ (0.03)
Capital expenditures	**$ 22,674**	$ 30,687	**$ 59,203**	$ 93,358
Net debt (1)	**$ 80,428**	$ 151,014	**$ 80,428**	$ 151,014
Total assets	**$ 628,542**	$ 870,908	**$ 628,542**	$ 870,908
Common Shares *(thousands)*				
Weighted average during period				
- basic and diluted	**214,188**	214,188	**214,188**	214,188
Outstanding at period end	**214,188**	214,188	**214,188**	214,188

(1) Cash flow, net debt, corporate netback, net production expense and cash G&A are not IFRS measures as defined throughout this MD&A. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

Operations

Petroleum and Natural Gas Production and Sales Volumes

Three months ended September 30	2012				2011			
	Oil (bbl/d)	Natural Gas Liquids (bbl/d)	Natural Gas (mcf/d)	Total [(1)] (boe/d)	Oil (bbl/d)	Natural Gas Liquids (bbl/d)	Natural Gas (mcf/d)	Total [(1)] (boe/d)
Production								
Canada	**1,567**	**1,141**	**42,646**	**9,816**	2,519	1,343	55,597	13,130
Tunisia	**1,949**	**-**	**1,193**	**2,148**	1,186	-	767	1,313
Total[(1)]	**3,516**	**1,141**	**43,839**	**11,964**	3,705	1,343	56,364	14,443
Sales								
Canada	**1,567**	**1,141**	**42,646**	**9,816**	2,519	1,343	55,597	13,130
Tunisia	**2,362**	**-**	**1,193**	**2,561**	1,256	-	767	1,384
Total[(1)]	**3,929**	**1,141**	**43,839**	**12,377**	3,775	1,343	56,364	14,514

Nine months ended September 30	2012				2011			
	Oil (bbl/d)	Natural Gas Liquids (bbl/d)	Natural Gas (mcf/d)	Total [(1)] (boe/d)	Oil (bbl/d)	Natural Gas Liquids (bbl/d)	Natural Gas (mcf/d)	Total [(1)] (boe/d)
Production								
Canada	**1,882**	**1,155**	**45,182**	**10,567**	2,778	1,453	55,582	13,496
Tunisia	**1,628**	**-**	**1,033**	**1,800**	800	-	793	932
Total[(1)]	**3,510**	**1,155**	**46,215**	**12,367**	3,578	1,453	56,375	14,428
Sales								
Canada	**1,882**	**1,155**	**45,182**	**10,567**	2,778	1,453	55,582	13,496
Tunisia	**1,506**	**-**	**1,033**	**1,678**	732	-	793	864
Total[(1)]	**3,388**	**1,155**	**46,215**	**12,245**	3,510	1,453	56,375	14,360

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

Chinook's predominately crude oil Tunisian production volumes of 2,148 boe per day and 1,800 boe per day during the third quarter and year to date 2012, increased by 64% and 93%, respectively, relative to the same periods of 2011. This increase entirely reflects the production from Chinook's Ordovician oil discovery located on the Bir Ben Tartar Concession ("BBT"). The third quarter of 2012 also marks a transition for Chinook, as for the first time in Chinook's history its Tunisian produced crude oil volumes exceed that of its Canadian operations. During the third quarter, Chinook drilled and completed its BBT TT13 horizontal well, which followed the drilling of its BBT TT16 horizontal well during the second quarter of 2012, with both wells accessing the Ordovician Quartzite reservoir (1.72 net wells). Both of these new horizontal wells began producing during the third quarter of 2012. The increased production from these new wells resulted in an average September 2012 Tunisian net production volume of 2,771 boe per day which included a maximum net production rate of 3,450 boe per day which was then subsequently temporarily restricted due to capacity constraints and limitations on crude oil trucking and surface water handling.

Production levels of Chinook's Canadian segment decreased approximately 3,300 boe per day, or 25%, for the third quarter as compared to the same period in 2011, as a result of the 2011 and 2012 non-core property dispositions and the shut-in of certain fields given the current natural gas price. This decrease includes approximately 2,300 boe per day of average production associated with the property and various unit interest dispositions made since the comparable period of 2011 and approximately 460 boe per day resulting from the shut-in of some of Chinook's dry gas fields, located primarily in north-eastern Alberta. Further volume declines resulted from third parties' facilities shut downs, turnarounds and pipeline failures, workovers, other repairs and maintenance, in addition to natural declines.

Production levels of Chinook's Canadian segment decreased approximately 2,900 boe per day, or 22%, for the year to date 2012 as compared to the same period of 2011. This decrease includes approximately 2,400 boe per day of average production associated with the property and various unit interest dispositions made during 2011 and year to date 2012 in addition to the reasons noted above as partially offset by Chinook's 2011 Canadian drilling, completion and tie-in programs.

The difference between Chinook's Tunisian production and sales volumes results from crude oil wellhead production being measured in the field versus revenue recognition being measured at the point when crude oil is loaded onto a tanker after first being transported and stored at a terminal facility at the port in La Skhira. The portion of crude oil production remaining stored in Chinook's tanks at each reporting date is reported as inventory. For the third quarter, crude oil sales exceeded production as Chinook sold approximately 77,000 barrels that were produced in the second quarter of 2012. For the year to date 2012, crude oil production exceeded sales resulting in approximately 37,000 barrels remaining in inventory as Chinook was awaiting a tanker to take delivery.

Drilling and completion expenditures for the third quarter totaled $19.7 million (comparable quarter of 2011 - $20.7 million), which included Chinook's Tunisian segment's drilling and completion expenditures of $17.1 million (comparable quarter in 2011 - $7.8 million). Third quarter Tunisian activity included the drilling of Chinook's BBT TT13 well (0.86 net) and completion of two (1.72 net), TT13 and TT16, horizontal wells. The TT13 and TT16 wells are the first multi-stage hydraulically fractured horizontal wells in Tunisia, the largest completed to date on the African continent and a successful application of North American drilling and completion technology.

Chinook's Canadian segment's drilling and completion expenditures for the third quarter totalled $2.6 million (comparable quarter of 2011 - $12.9 million) and included the drilling of one (0.25 net) well and the completion of two (0.75 net) wells.

Financial Results of Operations

Petroleum and Natural Gas Revenue and Realized Pricing

Three months ended September 30			2012			2011
($ thousands, except per unit amounts)	Canada	Tunisia	Total (1)	Canada	Tunisia	Total (1)
Oil sales	**$ 11,565**	**$ 22,993**	**$ 34,558**	$ 19,590	$ 13,126	$ 32,716
$/bbl	**80.23**	**105.82**	**95.61**	84.53	113.57	94.19
Natural gas liquids sales	**$ 5,924**	**$ -**	**$ 5,924**	$ 8,297	$ -	$ 8,297
$/bbl	**56.42**	**-**	**56.42**	67.15	-	67.15
Natural gas sales	**$ 8,706**	**$ 1,668**	**$ 10,374**	$ 18,838	$ 1,072	$ 19,910
$/mcf	**2.22**	**15.20**	**2.57**	3.68	15.19	3.84
Petroleum and natural gas revenue	**$ 26,195**	**$ 24,661**	**$ 50,856**	$ 46,725	$ 14,197	$ 60,923
$/boe	**29.01**	**104.68**	**44.67**	38.68	111.50	45.63

Nine months ended September 30			2012			2011
($ thousands, except per unit amounts)	Canada	Tunisia	Total (1)	Canada	Tunisia	Total (1)
Oil sales	**$ 43,086**	**$ 46,183**	**$ 89,269**	$ 65,282	$ 22,146	$ 87,428
$/bbl	**83.54**	**111.91**	**96.15**	86.08	110.91	91.25
Natural gas liquids sales	**$ 19,313**	**$ -**	**$ 19,313**	$ 25,407	$ -	$ 25,407
$/bbl	**61.03**	**-**	**61.03**	64.04	-	64.04
Natural gas sales	**$ 24,697**	**$ 4,515**	**$ 29,212**	$ 56,886	$ 3,062	$ 59,948
$/mcf	**1.99**	**15.96**	**2.31**	3.75	14.14	3.90
Petroleum and natural gas revenue	**$ 87,096**	**$ 50,698**	**$ 137,794**	$ 147,575	$ 25,208	$ 172,783
$/boe	**30.08**	**110.25**	**41.07**	40.05	106.92	44.08

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

Petroleum and natural gas revenue of $50.9 million and $137.8 million during the third quarter and year to date 2012 decreased $10.1 million and $35.0 million, respectively, from the same periods in 2011. This decrease was mostly due to lower Canadian petroleum and natural gas sales volumes and pricing. This effect was partially offset by increased Tunisian sales volumes.

Canadian Petroleum and Natural Gas Revenues

Chinook's Canadian petroleum and natural gas revenue for the current reporting periods, relative to the same periods in 2011, decreased as a result of lower Canadian petroleum and natural gas prices in addition to lower sales volumes resulting from the 2011 and 2012 non-core property dispositions, the temporary shut-in of predominantly dry gas fields and other production related issues.

Tunisian Petroleum and Natural Gas Revenues

Chinook's Tunisian petroleum and natural gas revenue for the current reporting periods, relative to the same periods in 2011, was higher as a result of increased crude oil sales volumes, and to a lesser extent, natural gas sales volumes. This increase in Tunisian petroleum and natural gas revenue for the year to date 2012 was further supported by higher commodity pricing.

Benchmark Prices

	Three months ended September 30		Nine months ended September 30	
	2012	2011	**2012**	2011
Oil				
Edmonton par ($/bbl)	**$ 84.39**	$ 91.81	**$ 86.91**	$ 94.32
Brent ($US/bbl)	**$ 109.95**	$ 111.31	**$ 112.46**	$ 110.55
Natural gas liquids				
WTI ($US/bbl)[(1)]	**$ 92.22**	$ 89.76	**$ 96.20**	$ 95.48
Natural gas				
AECO ($/mcf)	**$ 2.31**	$ 3.66	**$ 2.14**	$ 3.76

(1) West Texas Intermediate

Crude Oil Pricing

Chinook's year to date 2012 average crude oil realized price of $96.15 per barrel was an increase of five percent relative to the same period in 2011. This increase resulted from higher Brent benchmark pricing as Chinook's Tunisian crude oil production is sold at the three day average price for Brent oil quotations after being loaded onto a shipping tanker. The Brent benchmark continued to trade at a premium relative to WTI during the current reporting periods. Chinook's Canadian conventional crude oil production is sold at prices based on the Edmonton par benchmark postings, which during 2012 traded at a discount relative to WTI versus trading close to parity during 2011. Despite the increase in WTI, but consistent with the decrease in the Edmonton par benchmark, Chinook's Canadian crude oil sales price has decreased during the year to date 2012 as compared to the same period in 2011.

Natural Gas Liquids Pricing

Chinook's Canadian natural gas liquids price is a blend of prices received for a range of liquids from ethane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however Chinook benchmarks its liquids in reference to Edmonton par or WTI pricing. For the third quarter and year to date 2012, Chinook's realized natural gas liquids prices of $56.42 per barrel and $61.03 per barrel, respectively, approximated 69% and 76% of Edmonton par. These prices include the price received for propane, which continued to decrease with an ever widening discount relative to its reference price. When combined with lower Edmonton par benchmarks, Chinook's natural gas liquids prices decreased during the current reporting periods relative to the comparable periods. However, over the last six quarters, Chinook has averaged 78% of the Edmonton par crude oil price benchmark because its natural gas liquids are condensate rich.

Natural Gas Pricing

Chinook's Canadian realized natural gas prices of $2.22 per mcf and $1.99 per mcf for the third quarter and year to date 2012, respectively, were significantly lower than the prices realized during the same periods in 2011, reflecting the decreases in the AECO benchmark price.

Managing Commodity Price Risk

To mitigate commodity price risk, Chinook has entered into financial derivative contracts. Refer to "Commodity Price Risk Management Contracts and Swap Option" for a further discussion on Chinook's financial derivative contracts.

Royalties

Three months ended September 30			2012			2011
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 2,149**	**$ 695**	**$ 2,844**	$ 6,477	$ 526	$ 7,003
Per sales ($/boe)	**$ 2.38**	**$ 2.95**	**$ 2.50**	$ 5.36	$ 4.13	$ 5.24
Percent of revenue (%)	**8**	**3**	**6**	14	4	11

Nine months ended September 30			2012			2011
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 9,838**	**$ 1,456**	**$ 11,294**	$ 25,561	$ 1,733	$ 27,294
Per sales ($/boe)	**$ 3.40**	**$ 3.17**	**$ 3.37**	$ 6.94	$ 7.35	$ 6.96
Percent of revenue (%)	**11**	**3**	**8**	17	7	16

For the third quarter and year to date 2012, Chinook's royalties of $2.8 million and $11.3 million, respectively, decreased relative to the same periods in 2011. These decreases were the result of lower Canadian petroleum and natural gas revenues combined with an increase in the gas cost allowance recovery. This gas cost allowance recovery had the effect of lowering the Canadian operation's royalties per boe and the royalties as a percentage of revenue as reported in the third quarter and year to date 2012 relative to the same periods of 2011. The lower Canadian royalties per boe were also impacted by the effect of the lower realized average Canadian pricing used in the royalty formulas.

On a quarter over quarter basis, there was a modest increase in Tunisian royalties resulting from increased sales at Chinook's Adam Concession which saw its non-operated El Azzel N-2 well (0.05 net) brought onto production during the second quarter of 2012. For the year to date 2012, decreased crude oil sales volumes from the Adam Concession, despite relatively consistent production and pricing resulted in lower royalties as compared to the same period of 2011. The Adam Concession is under a joint venture contract where there is a royalty paid on crude oil and natural gas production based on a sliding scale calculation with royalty rates of between 2% to 15%. Presently, Chinook is paying an average royalty rate on its Adam Concession sales of 9% for natural gas and 12% for crude oil.

Chinook does not pay royalties on its BBT Concession's production. The current reporting periods' increase in Tunisian petroleum revenues was mostly the result of higher sales volumes from this Concession, in comparison to the same periods in 2011; therefore, the overall Tunisian royalty rate, as a percentage of revenue decreased to 3%, and on a per boe basis to $2.95 per boe and $3.17 per boe, respectively, for the third quarter and year to date 2012.

Production and Operating Expense

Three months ended September 30			2012			2011
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production and operating expense	**$ 15,788**	**$ 5,561**	**$ 21,349**	$ 25,020	$ 2,787	$ 27,807
Less:						
Processing and gathering revenue	**(419)**	**-**	**(419)**	(774)	-	(774)
Net production and operating expense (1)	**$ 15,369**	**$ 5,561**	**$ 20,930**	$ 24,246	$ 2,787	$ 27,033
Per sales net production and operating expenses ($/boe) (1)	**$ 17.02**	**$ 23.61**	**$ 18.38**	$ 20.07	$ 21.89	$ 20.25
Per sales production and operating expenses ($/boe)	**$ 17.48**	**$ 23.61**	**$ 18.75**	$ 20.71	$ 21.89	$ 20.82

Nine months ended September 30			2012			2011
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production and operating expense	**$ 51,066**	**$ 11,103**	**$ 62,169**	$ 67,793	$ 4,286	$ 72,079
Less:						
Processing and gathering revenue	**(5,229)**	**-**	**(5,229)**	(5,775)	-	(5,775)
Net production and operating expense (1)	**$ 45,837**	**$ 11,103**	**$ 56,940**	$ 62,018	$ 4,286	$ 66,304
Per sales net production and operating expenses ($/boe) (1)	**$ 15.83**	**$ 24.14**	**$ 16.97**	$ 16.83	$ 18.18	$ 16.91
Per sales production and operating expenses ($/boe)	**$ 17.63**	**$ 24.14**	**$ 18.53**	$ 18.40	$ 18.18	$ 18.39

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

For the third quarter and year to date 2012, production and operating expense of $21.3 million and $62.2 million decreased relative to the same periods in 2011. In Canada, the $15.8 million and $51.1 million of production and operating expense for the third quarter and year to date 2012, respectively, decreased relative to the same periods in 2011. These decreases resulted from Canadian dispositions of higher operating cost properties during 2011 and 2012 and Chinook's focus on cost savings, which also lowered production and operating expenses per boe. During the year to date 2012, Chinook has continued to focus on improving its Canadian operating cost structure which has resulted in various process changes and cost saving initiatives.

Further, Canadian production and operating expenses, including on a boe basis, for the current reporting periods are being unfavourably impacted due to the following factors where Chinook continues to incur production expenses with relatively little to no associated production volumes:

- the shut-in of certain dry gas fields which now includes the Red Creek field located in north eastern British Columbia in addition to Chinook's north-eastern Alberta dry gas fields;
- third party facility turnarounds and pipeline failures; and
- various production issues.

In Tunisia, an increase in the BBT Concession's sales volumes had the effect of increasing the Tunisian production and operating expense for the third quarter and year to date 2012, relative to the same periods in 2011. In addition, operating costs and operating costs per boe for the year to date 2012 increased as optimization work took place with velocity strings installed in the TT6, TT7 and TT9 wells to stabilize and improve production rates combined with the workover of the TT2 well. Chinook forecasts improved BBT operating costs on a boe basis as production volumes increase and the planned facility and potentially the sales line come on stream, as anticipated to occur in 2013.

Processing and gathering revenue is modestly lower in the third quarter and year to date 2012 as compared to the same periods in 2011. During the third quarter, Chinook made certain unfavourable prior period adjustments to estimates and billed rates totaling $1.2 million.

General & Administrative ("G&A") Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	**2012**	2011	**2012**	2011
Stock-based compensation	**$ 878**	$ 1,410	**$ 2,589**	$ 4,130
Rent and general office costs	**1,654**	1,760	**4,540**	5,185
Staffing, net of capitalized costs and recoveries	**933**	(96)	**2,094**	(665)
Legal expenses	**82**	59	**370**	699
Accounting and audit costs	**566**	69	**1,248**	646
Corporate expenses	**(611)**	346	**1,262**	1,286
G&A	**$ 3,502**	$ 3,548	**$ 12,103**	$ 11,281
Per sales ($/boe)	**$ 3.07**	$ 2.62	**$ 3.61**	$ 2.88
Cash G&A [1]	**$ 2,888**	$ 2,402	**$ 10,306**	$ 7,943
Per sales ($/boe)	**$ 2.54**	$ 1.80	**$ 3.07**	$ 2.03

(1) Cash G&A is not an IFRS measure and is calculated as G&A less stock-based compensation and the amortization of the deferred lease liability. Management uses this non-IFRS measure to assist them in understanding the current period's cash cost of G&A expenses.

G&A expense for the third quarter as compared to the same period in 2011 was relatively consistent; however with lower Canadian sales volumes mostly resulting from previous periods' non-core property dispositions, G&A expense increased to $3.07 per boe. These previous periods' non-core property dispositions, in addition to the shut-in of certain Canadian dry gas fields, have also resulted in significantly lower staffing recoveries due to the associated decreases in operating and capital expenditure activities. On November 1, 2012, Chinook reduced its Canadian office staffing levels to address the effect of the Canadian non-core property dispositions during 2011 and year to date 2012, the expectation of continued Canadian non-core property dispositions, and the shut-in of dry gas fields (approximately 2,860 boe per day in total) on its G&A per boe.

Corporate expenses for the third quarter and year to date 2012 included the recovery of accounts receivable of approximately $1.1 million that was previously assessed and expensed as uncollectible, but that was mostly collected during the current reporting periods.

Corporate Netbacks

The following tables outline the corporate netbacks by segment and on a consolidated basis:

Three months ended September 30			2012			2011
Per sales *($/boe)*	Canada [2]	Tunisia	Total	Canada [2]	Tunisia	Total
Realized sales price	**$ 29.01**	**$ 104.68**	**$ 44.67**	$ 38.68	$ 111.50	$ 45.63
Less:						
Royalties	**(2.38)**	**(2.95)**	**(2.50)**	(5.36)	(4.13)	(5.24)
Net production expense [3]	**(17.02)**	**(23.61)**	**(18.38)**	(20.07)	(21.89)	(20.25)
Cash G & A [4]	**(1.01)**	**(8.37)**	**(2.54)**	(1.67)	(2.49)	(1.80)
Corporate netback [1]	**$ 8.60**	**$ 69.75**	**$ 21.25**	$ 11.58	$ 82.99	$ 18.34

Nine months ended September 30			2012			2011
Per sales *($/boe)*	Canada [2]	Tunisia	Total	Canada [2]	Tunisia	Total
Realized sales price	**$ 30.08**	**$ 110.25**	**$ 41.07**	$ 40.05	$ 106.92	$ 44.08
Less:						
Royalties	**(3.40)**	**(3.17)**	**(3.37)**	(6.94)	(7.35)	(6.96)
Net production expense [3]	**(15.83)**	**(24.14)**	**(16.97)**	(16.83)	(18.18)	(16.91)
Cash G & A [4]	**(2.59)**	**(6.08)**	**(3.07)**	(1.89)	(3.55)	(2.03)
Corporate netback [1]	**$ 8.26**	**$ 76.86**	**$ 17.66**	$ 14.39	$ 77.84	$ 18.18

(1) Corporate netback is not an IFRS measure and is calculated as a period's sales of petroleum and natural gas, net of royalties less net production and operating expenses and cash G&A as divided by the period's sales volumes. Management uses this non-IFRS measure to assist them in understanding Chinook's 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.

Although both the Canadian and Tunisian corporate netbacks for the third quarter were lower than the comparable period in 2011, the total corporate netback increased as a result of the proportionately higher weighted average Tunisian crude oil sales volumes. For the third quarter of 2012, this resulted in a corporate netback of $21.25 per boe which represented 48% of the average realized sales price, both increases as compared to the same period in 2011.

As mentioned, despite an increase in Chinook's corporate netback on a boe basis, both of its operating countries are reporting lower netbacks for the third quarter as compared to the same period in 2011. The decrease, on a boe basis, in the Canadian corporate netback resulted from reductions in Canadian petroleum and natural gas pricing as partially offset by lower royalties, net production expense and Cash G&A. The Canadian Cash G&A on a boe basis decreased as Chinook charged a management fee from Canada to Tunisia to appropriately reflect the extent of Canadian resources dedicated to supporting the Tunisian operations. This Cash G&A adjustment is offset in the Tunisian netback and correspondingly has no effect on Chinook's netback. The Tunisian corporate netback for the third quarter, relative to the comparable period in 2011, on a boe basis, decreased due to lower Brent pricing and higher net production expense and Cash G&A expenses, as partially offset by lower royalties. This increase in net production expense and decrease in royalties, on a boe basis, is due to an increase in the weighted average of sales volumes from Chinook's BBT Concession as compared to those sales volumes from its Adam Concession.

Despite Chinook's corporate netback decreasing to $17.66 per boe for the year to date 2012, as compared to the same period in 2011, the netback has increased to 43% of the realized sales price as compared to 41%. This increase in the netback realized as a percentage of sales price is, again, attributable to the recent shift in the weighted average crude oil sales volumes towards Chinook's Tunisian operations which has a significantly higher corporate netback on a boe basis versus that received from its Canadian operations. The decrease, on a boe basis, in the corporate netback for the year to date 2012, as compared to the same period in 2011, resulted from lower Canadian petroleum and natural gas average realized sales prices combined with higher Cash G&A and Tunisian net production expenses. As mentioned, the Tunisian Cash G&A per boe reflects an increase attributable to a management fee from the Canadian operations, which has no effect on the total Cash G&A. However, the Tunisian Cash G&A on a boe basis is higher due to increased staffing levels and office costs for anticipated increased production levels.

Exploration and Evaluation Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	2012	2011	2012	2011
Canada	**$ 665**	$ 264	**$ 2,718**	$ 2,334
Tunisia	**236**	211	**4,684**	862
Total	**$ 901**	$ 475	**$ 7,402**	$ 3,196

Exploration and evaluation expense for the third quarter and year to date 2012 increased to $0.9 million and $7.4 million, respectively, from that reported during the same periods of 2011. During the third quarter 2012, exploration and evaluation expenditures were incurred for undeveloped land leases, studies over unlicensed lands or formations and prospecting expenses.

The increase in the Tunisian exploration and evaluation expense for the year to date 2012, as compared to the same period in 2011, is due to the expensing of drilling costs on two exploratory wells (0.96 net) both located onshore Tunisia, which includes the BJA-2 well (0.86 net), which was determined to be unsuccessful for petroleum or natural gas reserves. During the second quarter of 2012 the costs to complete and plug the BJA-2 well were expensed. The exploration and evaluation expense for the year to date 2012 also included a non-cash charge for the BJA-2 well related to its decommissioning obligation. These charges totalled $4.1 million for the year to date 2012.

Risk Management Contracts Losses (Gains)

	Three months ended September 30		Nine months ended September 30	
($ thousands)	2012	2011	2012	2011
Realized (gain) loss on commodity contracts	**$ (182)**	$ (561)	**$ (323)**	$ 723
Unrealized loss (gain) on commodity contracts	**5,111**	(2,924)	**(974)**	(6,071)
	$ 4,929	$ (3,485)	**$ (1,297)**	$ (5,348)

As at September 30, 2012, Chinook's crude oil swap was "in-the-money" whereas its crude oil collar price contracts were "out-of-the-money".

As Chinook receives a fixed crude oil price on a notional volume from its swap and collar commodity price contracts the unrealized loss during the third quarter of 2012 resulted from an increase in the September 30, 2012 forecasted Brent and WTI prices relative to these same measures at June 30, 2012. The unrealized gain during the year to date 2012 resulted from a decrease in these forecasted prices since being marked-to-market at December 31, 2011. Unrealized gains were also reported during the same periods in 2011 as generally the relevant forward benchmark prices were decreasing at the exit of each of these reporting dates, relative to those same measures at the beginning of each of these reporting dates.

The settlement of the swap and collar commodity price contracts for the current reporting periods and for the third quarter of 2011 resulted in gains whereas Chinook reported a loss during the year to date period in 2011. For the third quarter of 2012, Chinook reported a realized derivative gain as WTI has averaged below the fixed WTI price that Chinook receives on its swap crude oil contract. For the year to date 2012, in addition to realizing gains on its WTI swap crude oil contract, Chinook reported gains on its natural gas swaps, which expired in the first quarter of 2012. These realized gains in the current reporting periods were partially offset as Brent has averaged above the fixed Brent price that Chinook receives on one of its crude oil price collars. After including the realized gains on the crude oil derivative contracts, Chinook received an adjusted crude oil price of $96.12 per barrel as compared to its reported sales price of $95.61 per barrel for the third quarter and an adjusted crude oil price of $96.50 per barrel as compared to its reported sales price of $96.15 per barrel for the year to date 2012.

Net Financing Expenses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	2012	2011	2012	2011
Interest on bank debt	**$ 1,019**	$ 1,873	**$ 3,424**	$ 5,637
Interest earned on bank deposits	**(2)**	(3)	**(7)**	(25)
Finance charges and fees	**47**	(14)	**629**	620
Accretion of decommissioning obligation	**658**	952	**2,154**	2,842
Net financing expenses	**$ 1,722**	$ 2,808	**$ 6,200**	$ 9,074

The decrease in net finance expenses resulted from lower average outstanding debt during the current reporting periods. For the third quarter and year to date 2012, the effective interest rate on bank debt was 4.4% and 4.3%, respectively, which was relatively unchanged from 4.2% and 4.3%, for the comparable periods of 2011. The outstanding revolving term credit facility accrues interest at either Canadian prime and Banker's Acceptance rates plus a margin, depending on the option selected by Chinook.

The accretion expense decrease during the current reporting periods, as compared to the same periods in 2011, resulted from a comparatively lower risk free discount rate, in addition to a lower decommissioning obligation, due to non-core property dispositions and the December 31, 2011 downward estimate.

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

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	**2012**	2011	**2012**	2011
Canada	**$ 18,132**	$ 25,404	**$ 58,037**	$ 72,512
Tunisia	**7,331**	2,830	**13,872**	4,275
Total	**$ 25,463**	$ 28,234	**$ 71,909**	$ 76,787
Per sales ($/boe)	**$ 22.36**	$ 21.15	**$ 21.43**	$ 19.59

DD&A expense for the current reporting periods decreased from the same periods in 2011 due to decreases in sales volumes from Chinook's Canadian properties as a result of property dispositions during 2011 and year to date 2012, in addition to the current reporting periods' voluntary shut-ins. Partially offsetting this decrease was higher DD&A expense due to an increase in Chinook's BBT sales volumes which commenced production in September 2011.

For the third quarter and year to date 2012, DD&A was $22.36 per boe and $21.43 per boe, respectively, an increase relative to the same periods in 2011. BBT had the most notable impact on Chinook's depletion rate as this Concession's sales volumes increased over the comparative periods, mostly replacing lower Canadian sales volumes, but with a higher depletable rate. This Concession's higher depletion rate resulted from the terms of the profit sharing contract with ETAP, as Chinook includes 86% of the future development costs relative to a maximum of approximately 53% of the petroleum reserves. However, the economics of this higher BBT depletion rate are offset through Chinook not having to pay either petroleum royalties or income taxes from this Concession's sales volumes.

Impairment of Development & Production Assets

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	**2012**	2011	**2012**	2011
Canada	**$ -**	$ -	**$ 26,500**	$ -
Tunisia	**-**	-	**-**	-
Total	**$ -**	$ -	**$ 26,500**	$ -
Per sales ($/boe)	**$ -**	$ -	**$ 7.90**	$ -

At September 30, 2012, Chinook determined that there were no indications of impairment that would warrant a test for impairment. However, should future North American natural gas prices fall from Chinook's current outlook, the recoverable amount of the impaired dry natural gas weighted Canadian CGUs and Chinook's other Canadian CGUs will be sensitive to decreases in natural gas pricing and further impairment charges to those already taken on June 30, 2012, could be recognized in future reporting periods. Alternatively, an improvement of future North American natural gas prices, relative to Chinook's outlook, could support reversals of impairment charges recorded to date, less applicable depletion charges.

During the second quarter of 2012, Chinook reported an impairment charge of $26.5 million as triggered through a reduction in the forward price outlook of North American natural gas and, to a lesser extent, minimal development capital investment in Canada during the six months ended June 30, 2012. The impairment losses were recorded in predominately natural gas weighted Canadian cash generating units ("CGUs"). As of September 30, 2012, when combined with the impairment of $43.0 million as reported for the year ended December 31, 2011, Chinook's cumulative impairment charges totalled $69.5 million. The impairment tests were carried out at June 30, 2012 and were based on proved and probable reserves estimated internally by Chinook's reserve engineering staff as updated from the December 31, 2011 independent reserve report, a discount rate of ten percent and a forward commodity price outlook.

A one percent increase in the assumed discount rate would have resulted in an additional impairment of $8.8 million for the year to date 2012 reporting period, while a five percent decrease in the forward commodity price estimate would have resulted in an additional impairment of approximately $25.4 million.

Gain on Disposition of Properties

During the year to date 2012, Chinook completed the sale of five non-core petroleum and natural gas properties in addition to selling miscellaneous properties and several unit interests mostly located throughout Alberta, Canada, for net proceeds of $73.2 million, after including the final statement of adjustments for prior period dispositions. The carrying amount of the sold properties and unit interests, including the disposed decommissioning obligation, was less than the received sales proceeds resulting in a gain of $5.7 million for the nine months ended September 30, 2012 (versus a gain of $12.5 million for the same period in 2011).

Income Tax Expense (Recovery)

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2012**	**2011**	**2012**	**2011**
Current income tax	**$ 2,344**	$ 1,077	**$ 4,659**	$ 3,233
Deferred income tax (recovery)	**1,000**	(2,217)	**622**	(846)
Total	**$ 3,344**	$ (1,140)	**$ 5,281**	$ 2,387

Current income taxes relate to Chinook's Adam Concession, located onshore Tunisia. Current income tax increased to $2.3 million and $4.7 million during the third quarter and year to date 2012, respectively, as compared to the same periods of 2011. Contributing to this increase are lower deductions from declining tax bases, despite similar sales volumes and pricing, from Chinook's Adam Concession.

Deferred income taxes recognized in the current reporting periods, resulted from deductions of exploration expenditures allowed from the Adam Concession's taxable income. Chinook does not report deferred income tax recoveries from its Canadian operations as it applies a valuation allowance to these income tax assets.

Net Loss and Comprehensive Income (Loss)

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per share amounts)	**2012**	**2011**	**2012**	**2011**
Net loss	**$ (12,417)**	$ (3,543)	**$ (54,320)**	$ (5,675)
Per share - basic and diluted *($/share)*	**(0.06)**	(0.02)	**(0.25)**	(0.03)
Comprehensive (loss) income	**$ (15,887)**	$ 3,483	**$ (57,779)**	$ (141)
Per share - basic and diluted *($/share)*	**(0.07)**	0.02	**(0.27)**	(0.00)
Weighted average shares outstanding - basic and diluted *(thousands)*	**214,188**	214,188	**214,188**	214,188

Chinook's net losses of $12.4 million and $54.3 million for the third quarter and year to date 2012, respectively, increased relative to the same periods in 2011. These increases in the net losses were mostly due to lower Canadian sales revenue and higher expenses including unrealized losses on derivative contracts and current taxes. Additionally, for the year to date 2012, the increase in net loss as compared to the same period in 2011 was also due to an impairment charge of $26.5 million, lower gains on property dispositions and higher expenses including G&A and exploration and evaluation.

The comprehensive losses for the third quarter and year to date 2012, which includes Chinook's net losses and foreign currency translation losses, increased relative to the same periods in 2011. Chinook marked-to-market the Tunisian U.S dollar denominated net assets to the strengthening September 30, 2012 Canadian dollar spot rate, relative to the previous rates, resulting in a decrease in Chinook's reported Canadian dollar Tunisian net assets and correspondingly the recognition of net foreign exchange translation losses for the third quarter and year to date 2012.

Capital Resources, Capital Expenditures and Liquidity

Chinook continues to focus on project economics, scale and repeatability from opportunities in its existing asset base to grow conventional liquids production, test resource play concepts in Canada, and develop large scale production growth in Tunisia by accelerating the development of discoveries and existing fields.

During the fourth quarter of 2012, Chinook has engaged third parties to market for sale approximately 5,500 boe per day from its remaining Canadian non-core properties. Chinook anticipates it will fund its future work commitments on oil and natural gas properties from the sale of these non-core properties as well as cash flow generated from the Tunisian and Canadian operations and by utilizing, when necessary, the available funds from the credit facility.

Cash flow for the current reporting periods, in addition to proceeds from the disposition of Canadian non-core properties, financed the investment in capital, exploration and evaluation expenditures and increased non-cash working capital. In addition, during the year to date 2012 these cash inflows also financed the repayment of a portion of Chinook's revolving term credit facility.

Cash Flow

($ thousands, except per unit amounts)	Three months ended September 30 2012	Three months ended September 30 2011	Nine months ended September 30 2012	Nine months ended September 30 2011
Cash flow from operations	**$ 25,119**	$ 21,508	**$ 45,890**	$ 28,893
(Deduct) add back change in operating non-cash working capital	**(4,681)**	606	**1,540**	32,161
Add back decommissioning obligation expenditures	**497**	-	**2,509**	-
Cash flow (1)	**$ 20,935**	$ 22,114	**$ 49,939**	$ 61,054
Per share - basic and diluted (1)	**$ 0.10**	$ 0.10	**$ 0.23**	$ 0.29
Per sales ($/boe) (1)	**$ 18.39**	$ 16.56	**$ 14.88**	$ 15.57

(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 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 the ability of Chinook's operations 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 third quarter and year to date 2012 of $20.9 million and $49.9 million, respectively, decreased relative to that reported in the same periods of 2011 mostly due to lower Canadian sales volumes combined with lower Canadian petroleum and natural gas prices. This resulted in a decrease in cash flow per share on a basic and diluted share basis for the current reporting periods, compared to that reported during the same periods in 2011.

Revolving Term Credit Facility

($ thousands)	September 30 2012	December 31 2011
Outstanding balance on the revolving term credit facility	**$ 89,500**	$ 137,500
Less:		
Working capital excluding mark-to-market derivative contracts	**(9,072)**	(2,600)
Net debt (1)	**$ 80,428**	$ 134,900

(1) Net debt and working capital excluding mark-to-market derivate contracts are not 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 them in understanding Chinook's 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.

In June 2012, Chinook's 364 day revolving term credit facility was reduced to $115.0 million (the "Revolving Term Credit Facility") as a result of property sales and continued lower natural gas forecast prices as compared to $194.0 million as at December 31, 2011. The current revolving period ends on June 24, 2013. In the event that the revolving period is not extended prior to this date, all amounts then outstanding under the Revolving Term Credit Facility must be repaid before June 24, 2014. The Revolving Term Credit Facility is subject to a semi-annual review and redetermination. Changes in the availability of the Revolving Term Credit Facility are possible, from one renewal period to the next, with draws in excess of availability becoming immediately payable. At September 30, 2012, Chinook had drawn $89.5 million on the Revolving Term Credit Facility (December 31, 2011 - $137.5 million) resulting in available credit on this facility of $25.5 million (December 31, 2011 - $56.5 million).

Chinook's net debt of $80.4 million as at September 30, 2012, decreased relative to $134.9 million as at December 31, 2011 due to a $48.0 million net repayment of the principal outstanding on the Revolving Term Credit Facility, financed from cash flow and property sales during the nine months ended September 30, 2012 in addition to an increase of $6.5 million of working capital excluding mark-to-market derivative contracts.

The Revolving Term Credit Facility is collateralized by floating charges and security interests over all present and future properties and assets of the Company. Interest payable on amounts drawn on this facility vary based on Canadian prime or Bankers' Acceptance, depending on the borrowing option selected by Chinook. The effective interest rate on the Revolving Credit Term Facility for the third quarter and year to date 2012 was 4.4% and 4.3%, respectively, which is similar to the 4.2% and 4.3% reported for the comparable periods of 2011. The Revolving Credit Term Facility contains a covenant whereby the ratio of Chinook's debt to earnings 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. At September 30, 2012, Chinook was in compliance with this covenant.

Capital Expenditures

Three months ended September 30				2012				2011
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 242**	**$ -**	**$ -**	**$ 242**	$ -	$ 3	$ -	$ 3
Drilling and completions	**2,642**	**17,057**	**-**	**19,699**	12,115	7,819	-	19,934
Seismic and other	**-**	**-**	**-**	**-**	-	1,057	-	1,057
Facilities and equipment	**657**	**1,180**	**-**	**1,837**	8,283	424	-	8,707
Field expenditures	**3,541**	**18,237**	**-**	**21,778**	20,398	9,303	-	29,701
Capitalized G&A	**404**	**481**	**-**	**885**	524	51	-	575
Furniture and equipment	**-**	**-**	**10**	**10**	-	-	31	31
Property acquisitions	**1**	**-**	**-**	**1**	380	-	-	380
Total	**$ 3,946**	**$ 18,718**	**$ 10**	**$ 22,674**	$ 21,302	$ 9,354	$ 31	$ 30,687
Proceeds from dispositions	**$ 1,425**	**$ -**	**$ -**	**$ 1,425**	$ 22,981	$ -	$ -	$ 22,981

Nine months ended September 30				2012				2011
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 819**	**$ -**	**$ -**	**$ 819**	$ 2,842	$ 3	$ -	$ 2,845
Drilling and completions	**14,347**	**30,807**	**-**	**45,154**	40,996	18,530	-	59,526
Seismic and other	**-**	**-**	**-**	**-**	2,780	2,374	-	5,154
Facilities and equipment	**5,908**	**4,273**	**-**	**10,181**	18,823	1,081	-	19,904
Field expenditures	**21,074**	**35,080**	**-**	**56,154**	65,441	21,988	-	87,429
Capitalized G&A	**1,261**	**1,651**	**-**	**2,912**	1,550	327	-	1,877
Furniture and equipment	**-**	**-**	**61**	**61**	-	-	380	380
Property acquisitions	**76**	**-**	**-**	**76**	3,672	-	-	3,672
Total	**$ 22,411**	**$ 36,731**	**$ 61**	**$ 59,203**	$ 70,663	$ 22,315	$ 380	$ 93,358
Proceeds from dispositions	**$ 73,200**	**$ -**	**$ -**	**$ 73,200**	$ 52,941	$ -	$ -	$ 52,941

Drilling Activity Summary

Chinook's drilling activity for the third quarter and year to date 2012 is summarized below:

Three months ended September 30, 2012		Tunisia		Canada		Total
	Gross	Net	Gross	Net	Gross	Net
Oil	1.00	**0.86**	1.00	**0.25**	2.00	**1.11**
Gas	-	**-**	-	**-**	-	**-**
Dry	-	**-**	-	**-**	-	**-**
	1.00	**0.86**	**1.00**	**0.25**	**2.00**	**1.11**

Nine months ended September 30, 2012		Tunisia		Canada		Total
	Gross	Net	Gross	Net	Gross	Net
Oil	4.00	**2.63**	7.00	**2.50**	11.00	**5.13**
Gas	-	**-**	1.00	**1.00**	1.00	**1.00**
Dry	2.00	**0.96**	-	**-**	2.00	**0.96**
	6.00	**3.59**	**8.00**	**3.50**	**14.00**	**7.09**

Chinook's detailed activities by operating segment for the third quarter of 2012 are as follows:

Canada Capital Expenditures

The third quarter of 2012 was operationally quiet for Chinook in Canada. Only one well (0.25 net) was drilled at the Winmore, Saskatchewan Frobisher oil field, and two horizontal wells (0.75 net) were completed, both in the Wapiti, Alberta area for Dunvegan oil and gas production. The Winmore well was placed on production in late October at an initial rate of 170 barrels of oil per day (43 barrels of oil per day net). One non-operated Wapiti well was placed on production in late August, while the other operated well requires frozen ground conditions before it can be tied into the production facilities. Stabilized production rates for these wells are expected to be similar to the rates obtained from offsetting Chinook wells, at around 125 – 275 boe per day.

The planned activity for the remainder of 2012 is expected to focus on oil drilling opportunities in the Karr and Kaybob areas of Alberta. A non-operated horizontal Dunvegan well (0.38 net) was drilled and cased at Karr in October 2012. Completion of this new well is expected in the fourth quarter of 2012, along with the drilling of one or two more horizontal wells (both 0.38 net) prior to year end. Chinook has identified another 16 drilling locations on this prospect in which it holds a working interest and expects to drill six or seven gross wells in 2013. At Kaybob, Chinook expects to spud a Montney horizontal oil well (0.38 net) prior to year end 2012, following up on a significant discovery well which was drilled and tested in early 2012. Both the discovery well and the new drill are expected to be tied-in to newly constructed production facilities and be on stream in January 2013. Chinook has identified six more locations on this prospect in which it has a 37.5% working interest, where there is a significant amount of offsetting industry activity taking place, and six to eight additional locations in which it has a 75% working interest.

Along with ongoing workover and optimization projects throughout Chinook's asset base, numerous plays and prospects are drill-ready or currently being advanced, the best of which will be selected for execution in 2013. Some of the most exciting opportunities include the horizontal oil development projects at Karr (Dunvegan), Kaybob (Montney), Beaverlodge/Albright (Dunvegan), Valhalla (Doig, Montney), Wapiti (Dunvegan), Elmworth (Doe Creek), and Gordondale (Halfway). These all consist of currently producing, large oil-in-place, Chinook owned properties which can benefit from horizontal well development through combinations of increased recovery factors, rate acceleration, pool extensions, and reserve additions. In addition to a large inventory of natural gas prospects, numerous other exploratory oil focused prospects on Chinook's existing acreage are ready to drill and include projects in Little Bow (Glauc), Chip Lake (Rock Creek), Knopcik (Charlie Lake), Boundary Lake (Charlie Lake) and Red Creek (Doig, Montney).

Tunisia Capital Expenditures

During the third quarter, Chinook drilled its TT13 horizontal well (0.86 net) and spudded its TT11 horizontal well (0.86 net), both part of Chinook's Ordovician oil discovery located on its BBT Concession. The TT13 well was completed with a 12 stage multi-stage hydraulic fracture stimulation of which 11 stages were successfully fracture stimulated and the well was brought on production mid-September at average gross rates of 3,251 barrels of oil per day (1,756 net) for the first 10 days and then subsequently temporarily restricted to 1,500 barrels of oil per day (810 net) due to capacity constraints and limitations on crude oil trucking and surface water handling.

The TT16 well (0.86 net) was completed with a multi-stage hydraulic fracture stimulation and brought on production in the third quarter of 2012 at an initial gross rate of approximately 900 barrels of oil per day and average gross production for the third quarter of approximately 729 barrels of oil per day (393 net).

On the Adam onshore permit, the planned drilling of the ENI operated Defla well (0.10 net) well was cancelled and no drilling activity was undertaken in the third quarter. Planning for a third development well or a side track of an existing well is underway and will be agreed upon by the partners during the last quarter of 2012.

During the remainder of 2012, Chinook anticipates the completion of TT11 and drilling the TT10 horizontal well on its BBT Concession. On the Adam Concession, there are plans to complete well workovers and the operator is considering plans to optimize the production of numerous wells through artificial lift installations.

Rationalization of Non-Core Canadian Properties

During the nine months ended September 30, 2012, Chinook completed the sale of five non-core petroleum and natural gas properties, various miscellaneous properties and several unit interests mostly located throughout Alberta, Canada, for aggregate net proceeds of $73.2 million, after including the final statements of adjustments for prior period dispositions. The non-core properties sold during the year to date 2012 included Manyberries, Coutts, Thorsby, Nipisi, Joffre, miscellaneous properties and certain unit interests. Chinook's average production from these sold properties was approximately 1,069 boe per day.

The funds received for the above dispositions were used to partially finance the repayment of a portion of the drawn Revolving Term Credit Facility and to partially fund Chinook's capital programs.

Chinook initially assigned fair value from the corporate and asset acquisitions in the first half of 2010 on the same basis to its non-core properties as it did to its core properties. Only after Chinook was able to thoroughly review its acquired property portfolio, was it in a position to identify non-core Canadian properties and commence with the property rationalization process. Through this sequence of events, Chinook has reported gains on sales to date on the majority of its property dispositions.

During the fourth quarter of 2012, rather than continuing its dispositions of individual properties, Chinook has engaged third parties to market for sale approximately 5,500 boe per day from its remaining non-core Canadian properties.

Joint Arrangement

During 2011, Chinook entered into an agreement with a wholly-owned subsidiary ("NZOG") of New Zealand Oil & Gas Ltd. whereby NZOG has the option to participate in the development of Chinook's Tunisian offshore Cosmos Concession, in which Chinook is recognized as the holder of an 80% working interest. Under the terms of the agreement, NZOG paid Chinook initial consideration of US$3.0 million to purchase a 40% working interest in the Cosmos Concession, subject to the satisfaction of certain conditions. NZOG's election to participate in or withdraw from the development of the Cosmos Concession will be made at the point of Final Investment Decision ("FID") subject to regulatory approval and positive project economics. On a positive election, Chinook and NZOG will each retain a 40% working interest in the Cosmos Concession, provided that NZOG pays the first US$19.0 million of Chinook's share of the costs and expenses (in addition to its own share) in respect of the development plan. A FID is anticipated to be considered by the partners in early 2013 with a recommendation for project sanctioning following shortly thereafter.

Effective July 1, 2012, Chinook received an update from InSite Petroleum Consultants Ltd. to the evaluation of the reserves for the offshore Cosmos South field located in the Cosmos Concession. The update included the assignment of 8.8 million barrels of proved plus probable reserves and 6.5 million barrels of total proved reserves to the Cosmos South field (100% prior to royalties). This represents a 39% increase in the proved plus probable reserves at the Cosmos South field since December 31, 2011.

Decommissioning Obligation

At September 30, 2012, Chinook reported decommissioning obligations of $87.1 million ($95.4 million at December 31, 2011) for the future abandonment and reclamation of Chinook's properties. The estimated obligation includes assumptions in respect of actual costs to abandon wells, facilities and reclaim properties, the time frame in which such costs will be incurred as well as annual inflation factors in order to calculate the undiscounted total future liability. This estimated future liability as at September 30, 2012 and December 31, 2011, is then discounted at a liability specific risk-free interest rate of 2.0% to 3.0%.

The accretion charge, as recognized in the consolidated statements of operations to reflect the increase in the obligation associated with the passage of time, decreased to $0.7 million and $2.2 million for the third quarter and year to date 2012, respectively, relative to the same periods in 2011. These decreases mostly resulted from a lower risk free discount rate, in addition to a lower decommissioning obligation as reported at December 31, 2011, resulting from non-core property dispositions and a downward estimate.

During the first nine months of 2012, additions to the decommissioning liability of $2.0 million related to the period's drilling activities whereas $2.5 million of expenditures were incurred under Chinook's abandonment and reclamation program, which included the plugging and abandoning of the Nessma well, located on the producing Adam Concession, the plugging of the BJA-2 well located in close proximity to the producing BBT Concession, both onshore Tunisia, with the remainder incurred on Canadian suspended wells.

During the nine months ended September 30, 2012, Chinook sold five non-core properties, various miscellaneous properties and several unit interests resulting in the disposition of $9.9 million in decommissioning obligations as these obligations were assumed by the buyers of these properties and unit interests.

Outstanding Share Data

Authorized:

- Unlimited number of common shares;
- Unlimited number of first preferred shares; and
- 1,279,000 share purchase warrants (where each share purchase warrant is exercisable to acquire one common share of Chinook at a price of $3.25 per common share on or before June 30, 2013).

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

	September 30 2012	December 31 2011
Common shares outstanding	**214,187,681**	214,187,681
Share options	**15,061,721**	15,454,854
Share purchase warrants	**1,279,000**	1,279,000
Fully diluted common shares	**230,528,402**	230,921,535
Weighted average common shares - basic and diluted	**214,187,681**	214,187,681

At November 12, 2012, Chinook had 214,187,681 common shares, 14,462,581 options and 1,279,000 share purchase warrants outstanding.

Commodity Price Risk Management Contracts and Swap Option

Chinook's financial results are influenced by fluctuations in commodity prices. As a means of managing this price volatility, Chinook has entered into crude oil commodity price contracts. Currently, Chinook's commodity price risk management contracts provide price protection on approximately 15% of its estimated remaining annual production for 2012. Unsettled risk management contracts are recognized at their 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. Changes in fair value between reporting periods are recognized in net income (loss) as unrealized risk management contract gains or losses. Realized risk management contract gains or losses are recognized in net income (loss) upon the unwinding of the financial derivative contract term. While risk management contracts may have opportunity costs when realized commodity prices exceed the contracted price, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such financing techniques.

At September 30, 2012, Chinook had the following commodity price contracts with an estimated financial asset carrying amount of $0.7 million on the WTI indexed contract and an estimated financial liability carrying amount of $1.6 million on the Brent indexed contracts:

Crude Oil Indexed Price	Notional Volumes	Company's Received Price	Remaining period
WTI (1)	1,000 bbl/d	$98.75 US/bbl	July 1, 2012 to December 31, 2012
Brent	500 bbl/d	$100.00 US/bbl to $107.00 US/bbl	July 1, 2012 to December 31, 2012
Brent (2)	500 bbl/d	$100.00 US/bbl to $133.00 US/bbl	July 1, 2012 to December 31, 2012
Brent (3)	500 bbl/d	$100.00 US/bbl to $123.50 US/bbl	January 1, 2013 to December 31, 2013

(1) West Texas Intermediate.

(2) If the market price for Brent crude exceeds the US$133.00/bbl ceiling price, the notional volumes of the contract would double to 1,000 bbl/d and Chinook would receive a price of US$116.50/bbl, the mid-point between the floor and the ceiling price range, on the adjusted notional volume.

(3) If the market price for Brent crude exceeds the US$123.50/bbl ceiling price, the notional volumes of the contract would double to 1,000 bbl/d and Chinook would receive a price of US$111.75/bbl, the mid-point between the floor and the ceiling price range, on the adjusted notional volume.

On or before December 31, 2012, the counterparty to the US$98.75 per barrel swap crude oil price contract has the option, but not the obligation, to extend the commodity contract over the period January 1, 2013 to December 31, 2013, at the same strike price, indexed market and notional volume as the original swap crude oil contract. The effect of an increase in the September 30, 2012 forecasted WTI price has been offset by the passage of time resulting in Chinook continuing to report a $1.1 million financial liability as the fair value of this swap option, as previously measured and reported at June 30, 2012. Relative to the $3.6 million measured financial liability as at December 31, 2011, the option's measurement has decreased due to a decrease in the September 30, 2012 forecasted WTI price and the passage of time.

Subsequent to September 30, 2012, Chinook entered into a natural gas costless collar contract to sell a notional quantity of 4,000 GJ per day with a lower and upper strike price of $3.00 per GJ and $3.72 per GJ, respectively, commencing January 1, 2013 for a term of one year. With this costless collar contract, Chinook receives the ability to participate in a greater increase in the AECO benchmark with no required contract premium.

Outlook

Chinook has engaged third parties to market certain of its non-core Canadian assets. These assets represent approximately 5,500 boe per day, or 58% of Chinook's current Canadian production of 9,500 boe per day. Information memorandums are expected to be sent to prospective parties by mid-November 2012 with bids on these properties anticipated to be received early in 2013. This asset sale process is anticipated to accelerate and complete the disposition of non-core Canadian assets which to date has generated proceeds of approximately $161 million, before closing adjustments, through 30 transactions over the last seven quarters. Based on Chinook's relatively low existing debt to cash flow, it is well positioned to consider a broad range of forms of consideration for these assets. Dispositions of Chinook's non-core assets will enable it to focus its efforts on its Grande Prairie and Peace River Arch prospect inventory where it holds approximately 200,000 acres of undeveloped land.

The Company has established a provisional capital budget of $140-$145 million for 2013 which assumes Chinook will own all of the non-core Canadian assets that are being marketed as set forth above. To the extent the foregoing non-core asset sales are completed, the net sales proceeds therefrom will initially be applied to reducing the outstanding indebtedness of the Company, and the provisional capital budget for 2013 will be adjusted and approved.

The following table sets forth Chinook's guidance for 2013 which is based upon the provisional capital budget for 2013.

2013 Guidance

($ millions, except boe/d)	Consolidated	International	Canada
Production (boe/d)	10,800-11,500	3,000-3,400	7,800-8,100
Cash Flow	$ 130-135	$ 90-94	$ 38-41
Capital Expenditures	$ 140-145	$ 90-95	$ 45-50
Debt	$ 95-100		

The provisional capital budget is based upon an average AECO natural gas benchmark price of $3.26 per mcf, an average Canadian oil price of $88.94 per barrel and an average Tunisian oil price, as benchmarked to Brent, of US$103.00 per barrel.

Quarterly Information

Summarized information by quarter for the two years ended September 30, 2012, appears below:

($ thousands, except where noted)	Sept. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011	Sept. 30 2011	Jun. 30 2011	Mar. 31 2011	Dec. 31 2010
OPERATIONS								
Production								
Oil *(bbl/d)*	**3,516**	3,195	3,819	4,206	3,705	3,394	3,634	3,552
Natural gas liquids *(bbl/d)*	**1,141**	1,122	1,202	1,591	1,343	1,329	1,692	1,410
Natural gas *(mcf/d)*	**43,839**	43,387	51,445	55,927	56,364	56,834	55,922	62,346
Average daily production *(boe/d)*	**11,964**	11,548	13,596	15,119	14,443	14,196	14,646	15,354
Sales Prices								
Average oil price *($/bbl)*	**$ 95.61**	$ 89.11	$ 101.06	$ 97.11	$ 94.19	$ 97.71	$ 82.38	$ 76.49
Average natural gas liquids price *($/bbl)*	**$ 56.42**	$ 55.46	$ 70.66	$ 71.23	$ 67.15	$ 67.03	$ 59.13	$ 55.93
Average natural gas price *($/mcf)*	**$ 2.57**	$ 2.08	$ 2.27	$ 3.31	$ 3.84	$ 4.00	$ 3.85	$ 3.47
Corporate Netbacks (1)								
Average commodity pricing *($/boe)*	**$ 44.67**	$ 33.97	$ 43.35	$ 47.00	$ 45.63	$ 44.74	$ 41.86	$ 38.34
Royalties *($/boe)*	**$ (2.50)**	$ (3.29)	$ (4.22)	$ (6.03)	$ (5.24)	$ (7.57)	$ (8.12)	$ (6.10)
Net production expenses *($/boe)* (1)	**$ (18.38)**	$ (14.46)	$ (17.65)	$ (17.75)	$ (20.25)	$ (16.96)	$ (13.48)	$ (11.29)
Cash G&A *($/boe)* (1)	**$ (2.54)**	$ (3.74)	$ (3.03)	$ (5.13)	$ (1.80)	$ (1.85)	$ (2.22)	$ (3.53)
Corporate netbacks *($/boe)* (1)	**$ 21.25**	$ 12.48	$ 18.45	$ 18.10	$ 18.34	$ 18.36	$ 18.04	$ 17.42
Wells Drilled *(net)*								
Oil	**1.11**	0.86	3.16	6.12	7.45	0.90	4.64	6.75
Gas	**-**	-	1.00	1.02	0.65	0.10	5.96	0.26
Dry	**-**	0.86	0.10	-	-	-	-	0.75
Total wells drilled *(net)*	**1.11**	1.72	4.26	7.14	8.10	1.00	10.60	7.76
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum and natural gas revenue, net of royalties (2)	**$ 48,012**	$ 29,979	$ 48,509	$ 57,274	$ 53,920	$ 47,204	$ 44,365	$ 47,227
Cash flow (1)	**$ 20,935**	$ 9,830	$ 19,174	$ 23,950	$ 22,114	$ 17,799	$ 21,140	$ 22,576
Per share - basic and diluted *($/share)*	**$ 0.10**	$ 0.05	$ 0.09	$ 0.11	$ 0.10	$ 0.08	$ 0.10	$ 0.11
Net loss (3)	**$ (12,417)**	$ (24,812)	$ (17,091)	$ (58,077)	$ (3,543)	$ (1,890)	$ (241)	$ (12,893)
Per share - basic and diluted *($/share)*	**$ (0.06)**	$ (0.12)	$ (0.08)	$ (0.27)	$ (0.02)	$ (0.01)	$ -	$ (0.06)
Capital expenditures	**$ 22,674**	$ 13,083	$ 23,446	$ 26,343	$ 30,687	$ 18,975	$ 43,696	$ 25,454
Net debt (1)	**$ 80,428**	$ 77,092	$ 89,182	$ 134,900	$ 151,014	$ 165,771	$ 176,542	$ 170,526
Total assets	**$628,542**	$ 637,238	$ 692,023	$ 745,403	$ 870,908	$ 864,568	$ 888,500	$ 805,732
Common Shares *(thousands)*								
Weighted average during period - basic and diluted	**214,188**	214,188	214,188	214,188	214,188	214,188	214,188	214,188
Outstanding at period end	**214,188**	214,188	214,188	214,188	214,188	214,188	214,188	214,188

(1) Cash flow, net debt, corporate netback, net production expense and cash G&A are not IFRS measures as defined throughout this MD&A. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

(2) Tunisian production of 77,000 barrels was not reported as sold at June 30, 2012.

(3) Includes $43.0 million and $26.5 million in impairment charges against Canadian properties for the three and six months ended December 31, 2011 and June 30, 2012, respectively.

Factors That Have Caused Variations over the Quarters

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

Generally, Chinook's Canadian non-core property disposition program, which commenced in 2011, has resulted in a lower trending of Canadian production volumes. This effect was offset by increased Tunisian crude oil production from Chinook's BBT Concession since the third quarter of 2011, including the drilling and completion of two horizontal wells in 2012, and resulted in increasing petroleum and natural gas revenue through to the fourth quarter of 2011. However, when combined with the decreasing trending of the AECO benchmark, as partially offset by an increasing trending Brent benchmark, the petroleum and natural gas revenues, net of royalties have decreased since the fourth quarter of 2011, with corresponding lower cash flow and net income (loss).

Of particular note, the average commodity price, corporate net back per boe and the petroleum and natural gas revenues, net of royalties for the second quarter of 2012 declined as a result of a significant increase in the relatively higher priced Tunisian crude oil production that remained unsold at the end of this quarter. Further, for the fourth quarter of 2011 and second quarter of 2012, $43.0 million and $26.5 million, respectively, of impairment charges taken against Canadian assets resulted in significantly higher net losses. 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 Chinook's Tunisian operations. Capital expenditures have historically been focused on organic growth in Canada but during the second quarter of 2012 have shifted in favor of Tunisian organic growth.

Please refer to "Results of Operations" and other sections of this MD&A for detailed discussions on variations during the comparative quarters and to Chinook's 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 below and in the Annual Information Form of Chinook for the year ended December 31, 2011, available on SEDAR at www.sedar.com, and in the "Forward-Looking Statements" section of this MD&A and in Chinook's other public filings before making an investment decision. If any of these risks or other risks occurs, Chinook's business, prospects, financial condition, results of operations and cash flows could be materially adversely impacted.

Political Risks

The Ennhada led interim coalition government has announced their intention to hold Presidential and Parliamentary Elections in mid-2013. Prior to finalizing a date, the current assembly must confirm the constitution, form of government, and ratify any changes. Despite broadly delivering on the objectives of the interim government from a political process reform perspective, unrest and associated instability continue to grow. Opponents on both sides of the centrist coalition have become more critical of the pace of economic reform and more vocal regarding the level of Islamic principled influence in the legal, political and human rights arenas. Demonstrations targeting commercial operations, for political statement as well as personal commercial gain, are on the rise. Chinook sees no reason to expect this trend to be reversed in 2013. In 2012, Chinook's field operations have experienced six onsite field demonstrations. To date, there has been no commercial impact on its operations as Chinook has successfully relied on its strong relationship with the security services in its areas of operations, an active and engaged community relations effort and most importantly, the efforts of its staff in dealing with the demonstrations.

Although it is very difficult to predict the near term outcome or long term implications of the evolution of the political process in Tunisia, all major political parties have signaled their continued support for direct foreign investment. With the opportunity to boost domestic production by at least 20%, Chinook's projects represent important economic developments on both a local and national level.

Availability of Drilling and Completion Equipment

Oil and natural gas exploration and development activities are dependent on the availability of drilling and completion equipment (typically leased from third parties) in the particular areas where such activities will be conducted. In Tunisia, drilling and completion equipment are particularly in short supply. Demand for such limited equipment may affect the availability of such equipment to Chinook and may delay exploration and development activities.

Requirements for Permits and Licenses

The operations of Chinook 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). The ability of Chinook to obtain, sustain or renew such licenses or permits on acceptable terms is subject to changes in regulations and policies and to the discretion of the Government of Tunisia.

Tunisian Legal System

Tunisia has a French civil law based system with less established precedent in commercial petroleum related litigation, 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.

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. The long-term commercial success of Chinook depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Chinook may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Chinook's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Chinook will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, management of Chinook may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Chinook.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also 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 or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, 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, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely 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 fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, Chinook 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 liability to Chinook. 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 Chinook's business, financial condition, results of operations and prospects. In accordance with industry practice, Chinook is not fully insured against all risks, nor are all risks insurable. Although Chinook maintains liability insurance in an amount that it considers consistent with industry practice, the nature of certain risks is such that liabilities could exceed policy limits or not be covered, in either event Chinook could incur significant costs.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Chinook is and will continue to be affected by numerous factors beyond its control. Chinook's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Chinook may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of Chinook's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of Chinook's reserves. Chinook might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Chinook's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. 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 the control of Chinook. 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. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on Chinook's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on Chinook's business, financial condition, results of operations and prospects.

Disclosure Controls and Procedures

Chinook's 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 Chinook is made known to Chinook's 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 Chinook in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

Chinook's 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 Chinook's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in Chinook's internal controls over financial reporting were identified during the three months ended September 30, 2012, that have materially affected, or are reasonably likely to materially affect, Chinook's internal controls over financial reporting.

It should be noted that a control system, including Chinook's 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 Chinook's shareholders with information regarding Chinook, including management's assessment of Chinook's 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", "guidance", "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.

Specifically, this MD&A contains forward-looking statements relating to: the volumes and estimated value of Chinook's petroleum and natural gas reserves; the expected volume of Chinook's petroleum and natural gas production for the full year 2013; future results from operations; future costs and expenses; future exploration and development activities (including drilling and completion plans) and related capital expenditures; Chinook's liquidity and financial capacity; anticipated future cash flows, capital expenditures and debt levels; Chinook's 2013 guidance as set forth in the "Outlook" section; future taxes payable and tax pools; future decommissioning liabilities; funding sources for Chinook's capital program; expectations regarding a positive FID being made by NZOG and the timing thereof and expectations of future plans regarding Canadian non-core asset sales process.

These forward-looking statements are based on certain key assumptions regarding, among other things: the ability of Chinook to continue to operate in Tunisia with limited logistical, security and operational issues; Chinook's ability to obtain equipment and services in a timely manner to carry out exploration and development activities; that NZOG will make a positive FID and retain a 40% working interest in the Cosmos Concession; Chinook's ability to obtain equity and debt financing on satisfactory terms; future oil and natural gas prices; future well production rates and reserve volumes; Chinook's ability to add commercially viable and economic production and reserves through exploration and development activities; future capital expenditure levels; the availability and cost of labour and other industry services; and interest and foreign exchange rates. The reader is cautioned that such assumptions, although considered reasonable by Chinook at the time of preparation, may prove to be incorrect. Chinook's forward-looking statements are based on internally generated budgets relating to drilling plans and related costs, expected results from drilling as well as estimated royalties, operating costs and administrative expenses. Chinook bases the commodity pricing for budget purposes on a range of publicly available pricing forecasts and also considers general economic conditions.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: political and security risks associated with Chinook's Tunisian operations; general economic, market and business conditions; industry capacity; fluctuations in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; fluctuations in foreign exchange or interest rates; uncertainty associated with credit risk and counterparty credit risk; changes in applicable tax laws; uncertainty associated with partner plans and approvals including that NZOG may not make a positive FID and elect to proceed with the Cosmos Concession; stock market volatility and market valuations; geological, technical, drilling and processing risks and other difficulties in exploring for producing petroleum reserves; delays resulting from or inability to obtain required regulatory approvals; ability to access sufficient capital from internal and external sources; and other factors, many of which are beyond the control of Chinook. Therefore, Chinook's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements. Many of these risks and uncertainties are discussed in Chinook's Annual Information Form for the year ended December 31, 2011 and other documents that Chinook files with the Canadian securities regulatory authorities.

There is no representation by Chinook that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Chinook does not undertake any obligation to update publicly or to revise any of the included 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.

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Condensed Consolidated Statements of Financial Position

(unaudited)

(in thousands of Canadian dollars)	September 30 2012	December 31 2011
Assets		
Current		
Cash	$ 15,971	$ 11,475
Accounts receivable *(note 3)*	45,358	48,539
Inventory *(note 4)*	1,777	452
Derivative contracts *(note 5)*	668	551
Prepaids and deposits	5,669	6,174
	69,443	67,191
Development & production assets *(note 6)*	542,734	647,512
Exploration & evaluation assets *(note 6)*	16,365	30,700
	$ 628,542	$ 745,403
Liabilities and Shareholders' Equity		
Current		
Accounts payable, accrued liabilities and other *(note 7)*	$ 54,334	$ 60,398
Derivative contracts & swap option *(note 5)*	2,417	3,580
Deferred disposition proceeds on joint arrangement *(note 6)*	3,051	3,051
Taxes payable	2,318	591
	62,120	67,620
Derivative contracts *(note 5)*	306	-
Long-term debt *(note 8)*	89,500	137,500
Decommissioning obligation *(note 9)*	87,073	95,432
Deferred income taxes	9,228	8,555
Deferred lease obligation	794	1,585
Shareholders' Equity		
Share capital	778,070	778,070
Contributed surplus	19,829	17,240
Deficit	(414,992)	(360,672)
Accumulated other comprehensive income (loss)	(3,386)	73
	379,521	434,711
	$ 628,542	$ 745,403

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statements of Operations and Comprehensive (Loss) Income

(unaudited)

	Three months ended September 30		Nine months ended September 30	
(in thousands of Canadian dollars, except per share amounts)	2012	2011	2012	2011
Revenue				
Petroleum & natural gas revenue	**$ 50,856**	$ 60,923	**$ 137,794**	$ 172,783
Royalties	**(2,844)**	(7,003)	**(11,294)**	(27,294)
Petroleum & natural gas revenue, net of royalties	**48,012**	53,920	**126,500**	145,489
Processing & gathering revenue	**419**	774	**5,229**	5,775
Petroleum, natural gas & other revenue, net of royalties	**48,431**	54,694	**131,729**	151,264
Expense				
Production & operating	**21,349**	27,807	**62,169**	72,079
General & administrative	**3,502**	3,548	**12,103**	11,281
Exploration & evaluation	**901**	475	**7,402**	3,196
Commodity contract loss (gain) *(note 5)*	**4,929**	(3,485)	**(1,297)**	(5,348)
Net financing expenses *(note 11)*	**1,722**	2,808	**6,200**	9,074
Depletion, depreciation & amortization *(note 6)*	**25,463**	28,234	**71,909**	76,787
Impairment of development & production assets *(note 6)*	**-**	-	**26,500**	-
Gain on disposition of properties *(note 6)*	**(867)**	-	**(5,734)**	(12,475)
Foreign exchange loss (gain) & other	**505**	(10)	**1,516**	(42)
	57,504	59,377	**180,768**	154,552
Loss before income taxes	**(9,073)**	(4,683)	**(49,039)**	(3,288)
Income taxes expense				
Current income tax expense	**2,344**	1,077	**4,659**	3,233
Deferred income tax expense (recovery)	**1,000**	(2,217)	**622**	(846)
	3,344	(1,140)	**5,281**	2,387
Net loss	**(12,417)**	(3,543)	**(54,320)**	(5,675)
Foreign currency translation (losses) gains on foreign operations	**(3,470)**	7,026	**(3,459)**	5,534
Comprehensive (loss) income	**$ (15,887)**	$ 3,483	**$ (57,779)**	$ (141)
Net loss per share, basic and diluted *(note 10(d))*	**$ (0.06)**	$ (0.02)	**$ (0.25)**	$ (0.03)

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

(in thousands of Canadian dollars, except common shares)	Common Shares (thousands)	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
Balance as at December 31, 2010	**214,188**	**$ 778,070**	**$ 11,593**	**$ (296,919)**	**$ (2,961)**	**$ 489,783**
Stock-based compensation *(note 10(c))*	-	-	4,130	-	-	4,130
Other comprehensive gain for the period	-	-	-	-	5,534	5,534
Net loss for the period	-	-	-	(5,675)	-	(5,675)
Balance as at September 30, 2011	**214,188**	**$ 778,070**	**$ 15,723**	**$ (302,594)**	**$ 2,573**	**$ 493,772**
Balance as at December 31, 2011	**214,188**	**$ 778,070**	**$ 17,240**	**$ (360,672)**	**$ 73**	**$ 434,711**
Stock-based compensation *(note 10(c))*	-	-	2,589	-	-	2,589
Other comprehensive loss for the period	-	-	-	-	(3,459)	(3,459)
Net loss for the period	-	-	-	(54,320)	-	(54,320)
Balance as at September 30, 2012	**214,188**	**$ 778,070**	**$ 19,829**	**$ (414,992)**	**$ (3,386)**	**$ 379,521**

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statements of Cash Flows

(unaudited)

	Nine months ended September 30	
(in thousands of Canadian dollars)	2012	2011
Operating Activities		
Net loss	**$ (54,320)**	$ (5,675)
Add (deduct):		
Accretion *(note 11)*	**2,154**	2,842
Depletion, depreciation and amortization *(note 6)*	**71,909**	76,787
Impairment of development & production assets *(note 6)*	**26,500**	-
Exploration & evaluation expense	**7,402**	3,196
Unrealized derivative transactions and swap option gain *(note 5)*	**(974)**	(6,071)
Gain on disposition of properties *(note 6)*	**(5,734)**	(12,475)
Stock-based compensation *(note 10 (c))*	**2,589**	4,130
Deferred income tax expense (recovery)	**622**	(846)
Foreign exchange and other non-cash charges	**(209)**	(834)
Decommissioning expenditures	**(2,509)**	-
Change in other non-cash working capital *(note 12)*	**(1,540)**	(32,161)
Cash flow from operating activities	**45,890**	28,893
Financing Activities		
Long-term debt repayment	**(48,000)**	(15,258)
Change in non-cash working capital *(note 12)*	**-**	(819)
Cash flow from financing activities	**(48,000)**	(16,077)
Investing Activities		
Capital expenditures	**(59,203)**	(93,358)
Exploration and evaluation expense	**(7,253)**	(3,196)
Proceeds on property dispositions *(note 6)*	**73,200**	52,941
Change in non-cash working capital *(note 12)*	**(20)**	18,079
Cash flow from investing activities	**6,724**	(25,534)
Change in cash, during the period	**4,614**	(12,718)
Cash, beginning of period	**11,475**	23,195
Cash, foreign exchange	**(118)**	525
Cash, end of period	**$ 15,971**	$ 11,002

Other supplementary cash flow information *(note 12)*

See accompanying notes to the condensed consolidated financial statements.

Notes to the Condensed Consolidated Financial Statements

(unaudited)

As at and for the three and nine months ended September 30, 2012 and 2011

Tabular amounts in thousands of Canadian dollars, except as noted

1. Reporting Entity

Chinook Energy Inc., formerly Storm Ventures International Inc., was incorporated under the laws of the Province of Alberta, Canada, on August 28, 2003.

These condensed consolidated financial statements include the accounts of Chinook Energy Inc. and its directly and indirectly wholly-owned subsidiaries (collectively, “Chinook” or the “Company”), after the elimination of intercompany balances and transactions.

Chinook’s current operations are to explore, develop and produce natural gas, crude oil and natural gas liquids in Canada and Tunisia. In addition to the corporate segment, each country in which Chinook conducts business has been treated as an identifiable reporting segment.

Chinook’s common shares are listed on the Toronto Stock Exchange under the symbol CKE. The head office and principal address of Chinook is Suite 700, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

2. Basis of Presentation

The unaudited condensed consolidated financial statements have been prepared following the same accounting policies as disclosed in Note 3 in the audited consolidated financial statements for the years ended December 31, 2011 and 2010. These unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2012, should be read in conjunction with the consolidated financial statements for the years ended December 31, 2011 and 2010 and the notes thereto. These unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2012, do not include all of the required disclosures for annual consolidated financial statements.

Statement of Compliance

These condensed consolidated financial statements have been prepared by management in accordance with IAS 34 ‘Interim Financial Reporting’ (“IAS 34”) using accounting principles consistent with International Financial Reporting Standards (“IFRS”) issued by the International Accounting Standards Board (“IASB”).

These condensed consolidated financial statements were approved and authorized for issuance by the Board of Directors on November 13, 2012.

Basis of Measurement

The condensed consolidated financial statements have been prepared on the historical cost basis with the exception of derivative financial instruments which have been measured at fair value.

Functional and Presentation Currency

These condensed consolidated financial statements are presented in Canadian dollars which is also the Company’s Canadian and Corporate segments’ functional currency. The Tunisian segment’s functional currency is the United States dollar.

Management Judgment and Estimation Uncertainty

The use of judgments and estimates used in the preparation of these condensed consolidated financial statements have been applied consistently for all periods presented and are unchanged from the judgments and estimates disclosed in the notes to the consolidated financial statements for the year ended December 31, 2011, with the exception of:

Recoverability of asset carrying values

At June 30, 2012 it was determined that an impairment test was required for Chinook’s Canadian Cash Generating Units (“CGUs”) due to the reduced forward price outlook for natural gas and, to a lesser extent, minimal development capital investment in Canada during the six months ended June 30, 2012.

At June 30, 2012 the recoverable amounts of Chinook’s Canadian CGU’s were estimated as to their fair value less cost to sell based on the following information:

a) The net present value, discounted at 10%, of the cash flows from oil and gas reserves of each Canadian CGU based on reserves estimated internally by Chinook’s reserve engineering staff as updated from the December 31, 2011 independent reserve report; and

b) Consideration of acquisition metrics of recent transactions completed on similar assets to those contained within the relevant CGU.

Key input estimates used in the determination of cash flows from oil and 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 or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

b) **Oil and natural gas prices –** forward price estimates of the oil and natural gas prices are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

c) **Discount rate –** the discount rate used to calculate the net present value of cash flows is based on estimates of the Company's weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

Impairment tests as carried out at June 30, 2012, were based on proved and probable reserves, using a discount rate of 10 percent and the following forward commodity price estimates:

Year	Edmonton Light Crude Oil ($/bbl) [1][2]	AECO Gas ($/mmbtu) [1][3]	US/Cdn Exchange (US$/Cdn) [1]
2012 (6 months)	$ 87.30	$ 2.75	0.975
2013	$ 91.20	$ 3.50	0.975
2014	$ 95.00	$ 4.00	0.975
2015	$ 96.90	$ 4.60	0.975
2016	$ 98.90	$ 5.00	0.975
Thereafter	2%/yr	2%/yr	0.975

(1) Source: McDaniel & Associates Consultants Ltd. price forecast, effective July 1, 2012.
(2) Central market point for Canadian crude oil.
(3) Central market point for Canadian natural gas.

Relative to the last test for impairment at June 30, 2012, Chinook determined that there were no further indications of impairment that would warrant a test for further impairment as at September 30, 2012. For the nine months ended September 30, 2012, Chinook recorded an impairment of $26.5 million ($nil for the nine months ended September 30, 2011). A one percent increase in the assumed discount rate would result in an additional impairment of $8.8 million for the nine months ended September 30, 2012, while a five percent decrease in the forward commodity price estimate would result in an additional impairment of approximately $25.4 million.

3. Accounts Receivable

The Company's accounts receivable was comprised of:

	September 30 2012	December 31 2011
Trade accounts receivable	**$ 28,314**	$ 26,429
Accrued trade accounts receivable	**11,874**	17,526
Other receivables	**2,170**	6,278
Cash call receivables	**4,792**	1,229
Allowance for doubtful accounts	**(1,792)**	(2,923)
	$ 45,358	$ 48,539

The Company's accounts receivable balance was aged as follows:

	September 30 2012	December 31 2011
Not past due	**$ 38,657**	$ 43,118
Past due by more than 90 days, net of allowance	**6,701**	5,421
	$ 45,358	$ 48,539

4. Inventory

Inventory is comprised of crude oil produced in Tunisia that is either in transit from the wellheads or is being stored at terminal facilities awaiting delivery to shipping tankers. Chinook values its crude oil inventory at the lower of cost or net realizable value. As determined on a concession by concession basis, cost is measured as Chinook's expenses related to the operation, depletion and, if applicable, the royalties associated with the production of the crude oil inventory.

As at September 30, 2012 and December 31, 2011, Chinook valued its crude oil inventory on a cost basis. Chinook sold the approximately 10,000 barrels of crude inventory that it held at December 31, 2011 during the nine months ended September 30, 2012, as reported through the statement of operations. At September 30, 2012, Chinook had approximately 37,000 barrels of crude oil inventory.

5. Derivative Contracts and Swap Option

The impact on Chinook's net gain from commodity price risk management contracts and the swap option contract for the three and nine months ended September 30, 2012 and 2011 were as follows:

	Three months ended September 30		Nine months ended September 30	
	2012	2011	**2012**	2011
Realized (gain) loss on commodity contracts	**$ (182)**	$ (561)	**$ (323)**	$ 723
Unrealized loss (gain) on commodity contracts	**5,111**	(2,924)	**(974)**	(6,071)
	$ 4,929	$ (3,485)	**$ (1,297)**	$ (5,348)

Chinook uses commodity price risk management contracts to reduce its exposure to fluctuations in commodity prices. The following price risk management contracts were in place as at September 30, 2012:

Crude Oil Indexed Price	Notional Volumes	Company's Received Price	Remaining period
WTI (1)	1,000 bbl/d	$98.75 US/bbl	July 1, 2012 to December 31, 2012
Brent	500 bbl/d	$100.00 US/bbl to $107.00 US/bbl	July 1, 2012 to December 31, 2012
Brent (2)	500 bbl/d	$100.00 US/bbl to $133.00 US/bbl	July 1, 2012 to December 31, 2012
Brent (3)	500 bbl/d	$100.00 US/bbl to $123.50 US/bbl	January 1, 2013 to December 31, 2013

(1) West Texas Intermediate.

(2) If a future monthly average price for Brent crude exceeds the US$133.00/bbl ceiling price, the notional volumes of this contract would double to 1,000 bbl/d and Chinook would receive a price of US$116.50/bbl, the midpoint between the floor and ceiling price range, on the adjusted notional volume.

(3) If a future monthly average price for Brent crude exceeds the US$123.50/bbl ceiling price, the notional volumes of the contract would double to 1,000 bbl/d and Chinook would receive a price of US$111.75/bbl, the mid-point between the floor and the ceiling price range, on the adjusted notional volume.

The swap commodity price contracts are reported at their fair value as partially determined through the difference in the referenced market forward prices of the respective commodity over the remaining period of the contract as compared to the contract's strike price multiplied by the notional volumes during the remaining period. As at September 30, 2012, Chinook's fair value asset estimate of the WTI indexed swap commodity price contract was $0.7 million and the fair value liability estimate of the Brent indexed collar commodity price contracts was $1.6 million as compared to a fair value asset estimate of the swap commodity price contracts at December 31, 2011 of $0.6 million.

The swap option is reported at fair value as determined by a Black-Scholes model which includes the inputs of a forward WTI price and expected WTI price volatility over the remaining term of the swap option. On or before December 31, 2012, the counterparty to the US$98.75 per barrel swap crude oil price contract has the option, but not the obligation, to extend the commodity contract over the period January 1, 2013 to December 31, 2013, at the same strike price, indexed market and notional volume as the original swap crude oil contract. As at September 30, 2012, Chinook's fair value liability estimate of the swap option was $1.1 million (December 31, 2011 - $3.6 million).

Subsequent to September 30, 2012, Chinook entered into a natural gas costless collar contract to sell a notional quantity of 4,000 GJ per day with a lower and upper strike price of $3.00 per GJ and $3.72 per GJ, respectively, commencing January 1, 2013 for a term of one year.

6. Development & Production and Exploration & Evaluation Assets

The following table reconciles Chinook's development & production and exploration & evaluation assets:

	Development & Production Assets	Exploration & Evaluation Assets	Total
Cost of Assets			
Balance as at December 31, 2011	**$ 829,917**	**$ 58,226**	**$ 888,143**
Capital expenditures	58,517	686	59,203
Cost of properties sold	(92,635)	(1,150)	(93,785)
Change in decommissioning asset additions	1,879	-	1,879
Foreign exchange adjustment	(4,155)	-	(4,155)
Balance as at September 30, 2012	**$ 793,523**	**$ 57,762**	**$ 851,285**
Accumulated Depletion, Depreciation & Amortization			
Balance as at December 31, 2011	**$ (182,405)**	**$ (27,526)**	**$ (209,931)**
Depletion, depreciation & amortization	(57,390)	(14,519)	(71,909)
Impairment	(26,500)	-	(26,500)
Inventoried depletion	(747)	-	(747)
Reversed on sale	15,804	648	16,452
Foreign exchange adjustment	449	-	449
Balance as at September 30, 2012	**$ (250,789)**	**$ (41,397)**	**$ (292,186)**
Net Book Values			
Balance as at December 31, 2011	$ 647,512	$ 30,700	$ 678,212
Balance as at September 30, 2012	**$ 542,734**	**$ 16,365**	**$ 559,099**

The Company capitalized $2.9 million and $1.9 million of direct G&A costs as related to its exploration and development activity for the nine months ended September 30, 2012 and 2011, respectively.

Future development costs were added to the costs subject to depletion as follows:

	September 30 2012
Canada	**$ 31,070**
Tunisia	**67,386**
	$ 98,456

Impairment

For the nine months ended September 30, 2012, Chinook recognized an impairment charge of $26.5 million ($nil for the nine months ended September 30, 2011) as measured on June 30, 2012 and as triggered through a reduction in the forward price curve of Canadian natural gas and, to a lesser extent, minimal development capital investment in Canada during the six months ended June 30, 2012. The impairment loss was recorded in predominately natural gas weighted Canadian CGUs. As of September 30, 2012, when combined with the impairment of $43.0 million as reported for the year ended December 31, 2011, Chinook's cumulative impairment charges are $69.5 million. At a future date, if there is an indicator that a previously recognized impairment charge may no longer be valid, the recoverable amount of the relevant CGU will be calculated and compared against the carrying amount. An impairment charge could be recovered to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion, if no impairment loss had been recognized.

BJA-2 Exploration Well

During the first half of 2012, Chinook drilled its BJA-2 exploration well, located on its Sud Remada exploration permit onshore Tunisia. This well was determined to be unsuccessful for petroleum or natural gas reserves and the well costs of $4.1 million for the nine months ended September 30, 2012, were charged directly to exploration and evaluation expense as reported on the statement of operations.

Property Dispositions

During the nine months ended September 30, 2012, Chinook completed the sale of five petroleum and natural gas properties, in addition to the selling of miscellaneous properties and various unit interests mostly located throughout Alberta, Canada, for aggregate net proceeds of $73.2 million when combined with the final statements of operating adjustments on prior period petroleum and natural gas property sales ($52.9 million for the nine months ended September 30, 2011). The carrying amount of these sold properties, which has been reduced by $9.9 million of associated decommissioning obligations (note 9), was less than the sale proceeds received resulting in a gain of $5.7 million for the nine months ended September 30, 2012 ($12.5 million for the nine months ended September 30, 2011). For the three months ended September 30, 2012, Chinook recorded gains on the sale of petroleum and natural gas properties of $0.9 million ($nil for the three months ended September 30, 2011).

Joint Arrangement

During 2011, Chinook entered into an agreement with a wholly-owned subsidiary (“NZOG”) of New Zealand Oil & Gas Ltd. whereby NZOG has the option to participate in the development of Chinook’s Tunisian offshore Cosmos Concession, in which Chinook is recognized as the holder of an 80% working interest. Under the terms of the agreement, NZOG paid Chinook initial consideration of US$3.0 million to purchase a 40% working interest in the Cosmos Concession, subject to the satisfaction of certain conditions. NZOG’s election to participate in or withdraw from the development of the Cosmos Concession will be made at the point of Final Investment Decision (“FID”) subject to regulatory approval and positive project economics. On a positive election, Chinook and NZOG will each retain a 40% working interest in the Cosmos Concession, provided that NZOG pays the first US$19.0 million of Chinook’s share of the costs and expenses (in addition to its own share) in respect of the development plan. A FID is anticipated to be considered by the partners in early 2013 with a recommendation for project sanctioning following shortly thereafter.

7. Accounts Payable, Accrued Liabilities and Other

	September 30 2012	December 31 2011
Trade accounts payable	**$ 6,695**	$ 14,920
Accrued liabilities	**34,213**	30,108
Joint operations accounts payable	**11,913**	12,747
Royalties payable	**457**	1,567
Deferred lease obligation	**1,056**	1,056
	$ 54,334	$ 60,398

8. Long-Term Debt

In June 2012, Chinook’s 364 day revolving term credit facility (the “Revolving Term Credit Facility”) was reduced to $115.0 million as a result of property sales and continued lower natural gas forecast prices as compared to $194.0 million as at December 31, 2011. The current revolving period ends on June 24, 2013. In the event that the revolving period is not extended prior to this date, all amounts then outstanding under the Revolving Term Credit Facility must be repaid before June 24, 2014. The Revolving Term Credit Facility is subject to a semi-annual review and redetermination. Changes in the availability of the Revolving Term Credit Facility are possible, from one renewal period to the next, with draws in excess of availability becoming immediately payable. At September 30, 2012, Chinook had drawn $89.5 million on the Revolving Term Credit Facility (December 31, 2011 - $137.5 million) leaving available credit on this facility of $25.5 million (December 31, 2011 - $56.5 million).

The Revolving Term Credit Facility is collateralized by floating charges and security interests over all present and future properties and assets of the Company. Interest payable on amounts drawn on this facility vary based on Canadian prime, U.S. Base rate, U.S. LIBOR or Bankers’ Acceptance depending on the borrowing option selected by the Company. The effective interest rate on the Revolving Credit Term Facility for the three and nine months ended September 30, 2012 was 4.4% and 4.3%, respectively (2011 – 4.2% and 4.3%, respectively). The Revolving Credit Term Facility contains a covenant whereby the ratio of Chinook’s debt to earnings 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. At September 30, 2012, Chinook was in compliance with this covenant.

9. Decommissioning Obligation

The total future decommissioning obligations were estimated by management based on Chinook’s net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. Chinook has estimated the net present value of its total decommissioning obligation based on a total future undiscounted liability of $94.9 million ($106.3 million at December 31, 2011). At September 30, 2012, management estimated that these payments were expected to be made over the next 54 years. Risk free rates of 2% to 3% and inflation rates of 2% to 3% were used to calculate the present value of the decommissioning obligations.

Balance as at December 31, 2011	**$ 95,432**
Increase in liabilities relating to development activities	1,599
Increase in liabilities relating to change in estimates	427
Settlement of reclamation liabilities during the period	(2,509)
Decrease in liabilities relating to dispositions	(9,867)
Accretion expense	2,154
Foreign exchange adjustment	(163)
Balance as at September 30, 2012	**$ 87,073**

10. Share Capital

a) Authorized:

An unlimited number of no par value common shares and first preferred shares in addition to 1,279,000 share purchase warrants.

b) Issued and Outstanding:

Common Shares

All common shares are fully paid. The holders of common shares are entitled to share equally in dividends, returns of capital and to vote at shareholders' meetings.

First Preferred Shares

No first preferred shares have been issued.

Warrants

The Company issued 1,279,000 share purchase warrants ("Warrants") on May 27, 2010, in connection with a financing. As at September 30, 2012, all of the Warrants were outstanding. Each Warrant is exercisable to acquire one common share of the Company at a price of $3.25 per common share on or before June 30, 2013.

c) Stock-based Compensation Plan

The Company has a share option plan pursuant to which options to purchase common shares of the Company may be granted to employees, directors, officers, and other service providers of the Company. The maximum number of common shares issuable on exercise of options granted pursuant to the share option plan may not exceed 10% of the issued and outstanding common shares of the Company. The outstanding options of the Company vest over a period of three years and expire five years after the date granted.

A summary of options outstanding is as follows:

	Number of Options (thousands)
Balance as at December 31, 2011	**15,455**
Granted	1,279
Forfeited	(1,672)
Balance as at September 30, 2012	**15,062**

The table below summarizes outstanding stock options and the weighted average exercise prices, remaining life in years, the number of exercisable options and their respective weighted average exercise prices and remaining life.

	Outstanding Options			Options Exercisable		
Range of Exercise Prices ($/option)	Options Outstanding *(thousands)*	Weighted Average Exercise Prices *($/option)*	Weighted Average Remaining Life *(years)*	Options Outstanding *(thousands)*	Weighted Average Exercise Prices *($/option)*	Weighted Average Remaining Life *(years)*
$ 1.10 - $1.85	5,712	$ 1.53	4.1	476	$ 1.80	3.5
$ 1.86 - $2.20	6,187	2.10	2.6	3,477	2.05	2.3
$ 2.21 - $2.72	3,163	2.57	2.6	2,082	2.58	2.6
	15,062	$ 1.98	3.2	6,035	$ 2.21	2.5

Total stock-based compensation, as included in the line item general and administrative expenses in the condensed consolidated statements of operations, for the three and nine months ended September 30, 2012 was $0.9 million and $2.6 million, respectively (2011 - $1.4 million and $4.1 million). The following factors were used in the Black-Scholes pricing model for the determination of the fair value for options granted during the nine months ended September 30, 2012 and 2011:

Nine months ended September 30	2012	2011
Expected average life (years)	**1 to 3**	1 to 3
Risk-free interest rate (%)	**0.97 to 1.34**	1.42 to 2.84
Estimated forfeiture rate per annum (%)	**9.3 to 11.2**	0 to 30
Volatility factor (%)	**40 to 54**	58 to 59

The weighted average fair value determined for options granted during the three and nine months ended September 30, 2012 was $0.40 and $0.35 per option, respectively (2011 - $0.61 and $0.50 per option).

d) Per Share Amounts

The per share amounts for the three and nine months ended September 30, 2012 and 2011 were calculated as per the following table. Diluted income per share assumed the exercise of options and Warrants as if issued at the later of the date of grant or the beginning of the period. This calculation took into account only the options and Warrants that were considered to be "in-the-money". However, as Chinook had net losses across all reporting periods, the dilutive effect of "in-the-money" options and Warrants has been excluded in the calculation of diluted weighted average shares outstanding because inclusion would result in an anti-dilutive effect.

	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Net loss	**$ (12,417)**	$ (3,543)	**$ (54,320)**	$ (5,675)
Per share - basic and diluted ($/share)	**$ (0.06)**	$ (0.02)	**$ (0.25)**	$ (0.03)
Weighted average shares outstanding - basic and diluted (thousands)	**214,188**	214,188	**214,188**	214,188

11. Net Financing Expenses

	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Interest on bank debt and other interest	**$ 1,019**	$ 1,873	**$ 3,424**	$ 5,637
Interest earned on bank deposits	**(2)**	(3)	**(7)**	(25)
Finance charges and fees	**47**	(14)	**629**	620
Accretion of decommissioning obligation	**658**	952	**2,154**	2,842
Net financing expenses	**$ 1,722**	$ 2,808	**$ 6,200**	$ 9,074

12. Supplemental Disclosures

Changes in non-cash working capital:

Nine months ended September 30	2012	2011
Accounts receivable	**$ 2,388**	$ (23,775)
Accounts payable and accrued liabilities	**(5,400)**	12,399
Inventory	**(743)**	(301)
Prepaids, deposits and other	**469**	(1,216)
Taxes payable	**1,726**	(2,008)
	$ (1,560)	$ (14,901)
Operating activities	**$ (1,540)**	$ (32,161)
Investing activities	**(20)**	18,079
Financing activities	**-**	(819)
	$ (1,560)	$ (14,901)

Other supplemental cash flow information:

Nine months ended September 30	2012	2011
Cash taxes paid	**$ 2,932**	$ 5,416
Cash interest paid	**$ 3,424**	$ 5,639

13. Segmented Information

Chinook's continuing operating and reportable segments are as follows:

- Canada – includes the Company's Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in the Peace River and Grande Prairie areas located along the northern portion of the border of the Provinces of British Columbia and Alberta.
- Tunisia – includes eight blocks: offshore in the Gulf of Hammamet within the Pelagian Basin (Cosmos, Yasmin and Hammamet) with onshore properties located in Sud Remada, Bir Ben Tartar, Jenein, Adam and Borj El Khadra Blocks, all within the Ghadames Basin.
- Corporate – includes general and administrative costs and assets held corporately.

Selected Segment Information

Nine months ended September 30				2012				2011
	Canada	Tunisia	Corporate	Consolidated	Canada	Tunisia	Corporate	Consolidated
Capital expenditures	**$ 22,411**	**$ 36,731**	**$ 61**	**$ 59,203**	$ 70,663	$ 22,315	$ 380	$ 93,358

As at				September 30, 2012				December 31, 2011
Development & production and exploration & evaluation assets	**$440,934**	**$ 114,986**	**$ 3,179**	**$559,099**	$ 579,690	$ 95,395	$ 3,127	$ 678,212
Total assets	**$485,001**	**$ 131,686**	**$ 11,855**	**$628,542**	$ 631,048	$ 103,614	$ 10,741	$ 745,403

Results by Segment

		Canada		Tunisia		Corporate		Consolidated
Three months ended September 30	2012	2011	2012	2011	2012	2011	2012	2011
Revenue								
Petroleum, natural gas & other revenue, net of royalties	**$ 24,465**	$ 41,023	**$ 23,966**	$ 13,671	**$ -**	$ -	**$ 48,431**	$ 54,694
Expenses								
Production & operating	**15,788**	25,020	**5,561**	2,787	**-**	-	**21,349**	27,807
General & administrative	**764**	3,164	**850**	317	**1,888**	67	**3,502**	3,548
Exploration & evaluation	**665**	264	**236**	211	**-**	-	**901**	475
Commodity contract loss (gain)	**-**	-	**-**	-	**4,929**	(3,485)	**4,929**	(3,485)
Net financing expenses (recovery)	**1,683**	2,787	**37**	22	**2**	(1)	**1,722**	2,808
Depletion, depreciation & amortization	**18,132**	25,404	**7,331**	2,830	**-**	-	**25,463**	28,234
Gain on disposition of properties	**(867)**	-	**-**	-	**-**	-	**(867)**	-
Foreign exchange loss (gain) & other	**35**	(40)	**437**	26	**33**	4	**505**	(10)
	36,200	56,599	**14,452**	6,193	**6,852**	(3,415)	**57,504**	59,377
(Loss) income before income taxes	**(11,735)**	(15,576)	**9,514**	7,478	**(6,852)**	3,415	**(9,073)**	(4,683)
Income taxes								
Current income tax expense (recovery)	**5**	(54)	**2,339**	1,131	**-**	-	**2,344**	1,077
Deferred income tax expense (recovery)	**-**	(2,665)	**1,000**	448	**-**	-	**1,000**	(2,217)
	5	(2,719)	**3,339**	1,579	**-**	-	**3,344**	1,140)
Net (loss) income	**$ (11,740)**	$ (12,857)	**$ 6,175**	$ 5,899	**$ (6,852)**	$ 3,415	**$ (12,417)**	$ (3,543)

Nine months ended September 30	Canada 2012	Canada 2011	Tunisia 2012	Tunisia 2011	Corporate 2012	Corporate 2011	Consolidated 2012	Consolidated 2011
Revenue								
Petroleum, natural gas & other revenue, net of royalties	**$ 82,487**	$ 127,788	**$ 49,242**	$ 23,476	**$ -**	$ -	**$ 131,729**	$ 151,264
Expenses								
Production & operating	**51,066**	67,793	**11,103**	4,286	**-**	-	**62,169**	72,079
General & administrative	**2,836**	10,298	**1,562**	837	**7,705**	146	**12,103**	11,281
Exploration & evaluation	**2,718**	2,334	**4,684**	862	**-**	-	**7,402**	3,196
Commodity contract gain	**-**	-	**-**	-	**(1,297)**	(5,348)	**(1,297)**	(5,348)
Net financing expenses	**6,086**	9,028	**112**	44	**2**	2	**6,200**	9,074
Depletion, depreciation & amortization	**58,037**	72,512	**13,872**	4,275	**-**	-	**71,909**	76,787
Impairment of development & production assets	**26,500**	-	**-**	-	**-**	-	**26,500**	-
Gain on disposition of properties	**(5,734)**	(12,475)	**-**	-	**-**	-	**(5,734)**	(12,475)
Foreign exchange loss (gain) & other	**62**	(32)	**521**	(15)	**933**	5	**1,516**	(42)
	141,571	149,458	**31,854**	10,289	**7,343**	(5,195)	**180,768**	154,552
(Loss) income before income taxes	**(59,084)**	(21,670)	**17,388**	13,187	**(7,343)**	5,195	**(49,039)**	(3,288)
Income taxes								
Current income tax expense (recovery)	**5**	(167)	**4,654**	3,400	**-**	-	**4,659**	3,233
Deferred income tax expense (recovery)	**(893)**	(2,262)	**1,515**	1,416	**-**	-	**622**	(846)
	(888)	(2,429)	**6,169**	4,816	**-**	-	**5,281**	2,387
Net (loss) income	**$ (58,196)**	$ (19,241)	**$ 11,219**	$ 8,371	**$ (7,343)**	$ 5,195	**$ (54,320)**	$ (5,675)