BORDER PETROLEUM CORP.

(Formerly Border Petroleum Inc.)

MANAGEMENT'S DISCUSSION AND ANALYSIS

July 26, 2013

SUITE 2000, 840 – 7 AVENUE S.W.
CALGARY, ALBERTA T2P 3G2

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis of financial results and related data has been prepared by management, is reported in Canadian dollars and should be read in conjunction with the audited financial statements for the year ended March 31, 2013. The accompanying financial statements were approved by the Corporation's Audit Committee on behalf of the Board of Directors. The financial information presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"). Additional information relating to Border is filed at www.sedar.com. This Management's Discussion and Analysis is dated as of July 26, 2013.

BOE presentation** – **For the purposes of calculating unit costs, natural gas is converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one boe unless otherwise stated. A boe is a very approximate comparative measure that, in some cases, could be misleading, particularly if used in isolation.

FORWARD-LOOKING STATEMENTS

The information herein contains forward-looking statements and assumptions. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", continue", "estimate", "expect", "may", "will", "project", "predict", "potential, "targeting", "intend", "could", "might", "should", "believe" and other similar expressions. Such statements and assumptions also include those relating to guidance, results of operations and financial condition, capital spending, financing sources, commodity prices, cost of production and the magnitude of oil and gas reserves. By their nature, forward-looking statements are subject to numerous known and unknown risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. Border Petroleum Corp. is exposed to numerous operation, technical, financial and regulatory risks and uncertainties, many of which are beyond its control and may significantly affect anticipated future results.

Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, ability to attract and retain employees on a cost-effective basis, commodity and marketing risk and seasonality. Border Petroleum Corp. is subject to significant drill risks and uncertainties including the ability to find oil and natural gas reserves on an economic basis and the potential for technical problems that could lead to well blowouts and environmental damage. Border Petroleum Corp. is also exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third party gathering and processing facilities, transportation and other third party related operation risks. Furthermore, there are numerous uncertainties in estimating Border Petroleum Corp.'s reserve base due to the complexities in estimated future production, costs and timing of expenses and future capital. The financial risks Border Petroleum Corp. is exposed to include, but not limited to, access to debt or equity markets and fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate. Border Petroleum Corp. is subject to regulatory legislation, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties or production restrictions.

Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time preparation of, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Border Petroleum Corp. 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.

NON-IFRS MEASURES

This MD&A includes references to financial measures commonly used in the oil and gas industry. The terms "net petroleum and natural gas revenue" (petroleum and natural gas sales less royalties, production expenses and transportation costs) and "funds from operations" (net loss for the period adjusted for non-cash items in the statement of operations) have no standardized meanings, are not defined by IFRS, and accordingly are referred to as non-IFRS measures.

Border Petroleum Corp. also uses "operating netbacks" as a key performance indicator of field results by commodity. "Operating netbacks" do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other companies. Operating netbacks are determined by deducting royalties, operating, processing and transportation expenses from petroleum and natural gas sales.

Funds from operations and operating netbacks are not intended to represent operating profits, nor should they be viewed as an alternative to cash flow provided by operating activities, net loss or other measures of financial performance calculated in accordance with IFRS.

CORPORATION OVERVIEW

The primary business of Border Petroleum Corp. ("Border" or the "Corporation") is the acquisition, development and production of crude oil, natural gas and natural gas liquids from properties located in the province of Alberta. The Corporation's shares are posted on the TSX Venture Exchange (the "TSXV") under the symbol "BOR". The Corporation changed its name from Border Petroleum Inc. to Border Petroleum Corp. on September 14, 2010.

HIGHLIGHTS

The following are the highlights of Border's operations for the year ended March 31, 2013:

- *On July 16, 2012, the Corporation released initial results from its first two Slave Point horizontal wells in the Red Earth area (the "Initial Wells").*
- *On September 28, 2012, Border completed a short form prospectus offering for aggregate gross proceeds of $18,001,080.*
- *On November 29, 2012, Border announced the completion of its first long-leg Slave Point horizontal well located at 10-15-85-10W5M (the "10-15 Well") on the Loon River Cree Nation and the acquisition of 17 square kilometers of 3D seismic on the Loon Block.*
- *On February 28, 2013, Border provided an update with respect to the completion and testing of the 10-15 Well.*
- *Subsequent to its year-end, on April 29, 2013 Border announced the formation of a Special Committee of independent directors and the initiation of a strategic review process to identify, examine and consider a range of strategic alternatives with a view to maximizing shareholder value. The Special Committee retained Dundee Securities Ltd. and Macquarie Capital Markets Canada Ltd. as co-financial advisors to assist in the strategic review process.*

OUTLOOK

In light of the current public equity market environment for small cap oil and gas companies in general, and the effect on Border's share price given the results from the 10-15 Well to date in particular, on April 29, 2013 Border announced that its Board of Directors had formed a Special Committee of independent directors to initiate a strategic review process to identify, examine and consider a range of strategic alternatives with a view to maximizing shareholder value. As noted in the April 29th release, the strategic review process encompasses the potential for a sale of the Corporation, a sale of a material portion of the Corporation's assets, a merger, business combination or a corporate reorganization, among other alternatives. The Special Committee has retained Dundee Securities Ltd. and Macquarie Capital Markets Canada Ltd. as co-financial advisors to assist in the strategic review process. The strategic review process is currently on-going. As previously announced, Border does not intend to disclose developments with respect to the strategic review process unless and until the Board of Directors has approved a definitive transaction or strategic option, or unless otherwise required by law or disclosure of which is deemed appropriate.

OPERATIONS

The Corporation's average net daily production was 216 boe/d for the year ended March 31, 2013 compared to 227 boe/d for the last year. Average net daily production was 232 boe/d for the three months ended March 31, 2013 compared to 275 boe/d for the last year. The 10-15-85-10W5M well's production was up and down during this period with pump changes needed for optimization. In Norris, several wells were down for pump changes and are now waiting for dry conditions to complete this work. The production profile remains flat due to under performance of the Loon Block wells, corporate decline and waxing/ asphaltene issues in the Red Earth area.

Producing Properties

Red Earth/Dawson, Alberta

The Corporation has a working interest in 22,160 gross acres (22,117 net) in the Red Earth and Dawson area of northwestern Alberta (“Non-Reserve Lands”).
Of this the largest component is the Loon block which is 18,482 acres gross/net acres. The Corporation has re-entered five vertical wells on Crown Lands and drilled three new Horizontal wells on the Loon Block to date.
In the Red Earth area, Border has a 100% working interest in the wells 100/11-06-87-11W5M, 00/9-06-86-10W5M, 00/13-36-85-11W5M, 100/4-15-88-12W5M, 00/08-28-88-11W5M and 100/16-36-085-11 W5M/2. The Corporation has a well in the Dawson field located at 6-23-80-17W5M.

All wells operate as single well batteries with effluent trucked to local processing facilities. In Red Earth the 11-06-87-11W5M well has been shut in due to high operating costs and the 9-06-86-10W5M remains down for pump maintenance. The Corporation continues to treat the wells for asphaltene and waxing issues.

In October 2012 Border successfully drilled its first long-leg Slave Point horizontal well located at 10-15-85-10W5M (the “10-15 Well”). The 10-15 Well was drilled to a total depth of 3,250 meters, including a 1,630 meter horizontal leg. The horizontal leg of the well was extended by approximately 250 meters to test the extent of the higher porosity formation encountered at the toe of the well.

The well was fracture stimulated over 23 zones and put on production with a conventional tubing pump December 23 2012 and well produced in this manner until March 2nd when a mechanical failure shut the well in. At this time due to the high inflow it was decided to install a high volume Submersible Pump and the well was produced in this manner from March 8th to March 29th. At this time inflow had reduced to warrant releasing the rental equipment associated with the submersible pump and run back in with the conventional tubing pump. During this period the maximum total inflow reached 288m3/d (1812 bbl/d) with an average total inflow of 95m3/d (598 bbl/d) with cuts ranging from 0 percent to 7 percent oil. The 10-15 Well was put back on production April 5th and is currently shut in due to access road conditions associated with breakup with testing to resume following breakup.

Border Petroleum is in the process of obtaining approvals from the ERCB and IOGC for water disposal into the currently abandoned vertical well at 100/16-22-85-10WM to obtain approval for the disposal scheme into the Wabamun. Slave Point horizontal wells in the Red Earth area can produce between 50 to 90 percent water over a majority of their production life. Accordingly, the ability to dispose of water production from the 10-15 Well directly on-site, as well as from Border’s two short-leg horizontal wells located at 5-1-85-10-W5 (the “5-1 Well”) and 6-36-85-10W5 (the “6-36 Well”), will reduce Border’s current and future operating costs related to these wells and any future wells in the area.

With respect to Border’s 2 short-leg horizontal wells on the Loon Block, for the 3 months ended March 31, 2013, Border’s 5-1 Well and 6-36 Well combined oil rate averaged 15.9 bopd. As previously reported, production from these short horizontal wells has been impeded by wax and asphaltene build up which Border continues to address using cost effective remediation efforts. The two wells are currently producing at a combined oil rate of approximately 10.7 bopd. The Red Earth/Dawson production during the three and twelve months ended March 31, 2012, averaged 21 bbls/d and 24 bbls/d respectively. This year, the three and twelve months ended March 31, 2013, averaged 39 bbls/d and 41 bbls/d, respectively.

Leduc, Alberta

The Corporation has an interest in 4,820 gross acres (4,564 net) in the Leduc area of central Alberta. The Corporation has a 100% working interest in the wells 15-19-49-26W4M, 10-29-49-26W4M, 8-32-49-26W4M, 14-32-49-26W4M and 13-33-49-26W4M and 60% in 11-33-49-26W4M. Border is still investigating different options to conduct an acid or proppant stimulation on its 13-33-49-26W4M and 15-19-49-26W4M Nisku horizontal oil wells. The company has also conducted field operations on its 14-32-49-26W4M to re-equip to produce Wabamun gas. This has added approximately 50 boepd to the Leduc to give a current production of approximately 166 boepd (8 percent oil weighted) to the Leduc area. Border has an interest in 4,564 net acres in the Leduc area of central Alberta. The Leduc production during the three and twelve months ended March 31, 2012, averaged 194 boe/d and 147 boe/d, respectively. This year, the Leduc production for the three and twelve months ended March 31, 2013, averaged 147 boe/d and 129 boe/d, respectively.

Norris, Alberta

The Corporation has various working interests varying from 57.5% to 100% in 520 gross acres (452 net acres) in the Norris area of central Alberta which also consists of five producing oil wells and one water disposal well. The Corporation has a 57.5% working interest in the well 100/16-21-53-18W4M and 100.0% working interest in wells 102/16-21-53-18W4M, 00/01-28-53-18W4M, 102/01-28-53-18W4M and 100/04-27-053-18W4M which all produce from the Mannville formation. Several Norris wells had pump optimization performed during the previous reporting period with good results. The Norris production during the three and twelve months ended March 31, 2012, averaged 5 bbls/d and 12 bbls/d, respectively. This year, the Norris production for the three and twelve months ended March 31, 2013, averaged 16 bbls/d and 12 bbls/d, respectively.

Cherhill/Majeau, Alberta

Border has a 37.5% to 100% working interest in 3,170 acres (2,770 net acres) in the Cherhill area of southwestern Alberta. The wells, 100/03-25-56-04W5 and the 6-26-56-04W5M, produce from the Glauconite formation. The Cherhill/Majeau production during the three and twelve months ended March 31, 2012, averaged 10 bbls/d and 8 bbls/d, respectively. This year, the Cherhill/Majeau production for the three and twelve months ended March 31, 2013, averaged 9 bbls/d and 9 bbls/d, respectively.

Cardiff, Alberta

No production, as the 14-34-55-01W5M well remains shut in.

Pembina/Brazeau, Alberta

The Pembina shallow gas production from the acquisition of Canflame Energy Ltd. commencing July 14, 2011 had production to the end of March 31, 2012, averaging 35 boe/d, and 41 boe/d for the three months ended March 31, 2012. This year, the Pembina production for the three and twelve months ended March 31, 2013, averaged 21 boe/d and 26 boe/d, respectively.

Non-Producing Properties

Phat City, Montana, USA

The Corporation has expensed costs previously capitalized as exploration and evaluation assets related to Phat City totaling $915,790 as the there are no further plans to pursue these assets.

PRODUCTION SUMMARY

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	2012	CHANGE	2013	2012	CHANGE
Total Production						
Oil - bbls	**7,386**	4,671	58	**28,028**	22,322	26
Natural gas liquids - bbls	**3,127**	1,991	57	**7,215**	6,529	11
Natural Gas - Mcf	**62,366**	108,283	(42)	**261,998**	326,047	(20)
Total boe	**20,907**	24,709	(15)	**78,909**	83,192	(5)
Daily Production						
Oil - bbls per day	**82**	51	61	**77**	61	26
Natural gas liquids - bbls per day	**35**	22	59	**20**	18	11
Natural Gas - Mcf per day	**693**	1,190	(42)	**718**	891	(19)
Total boe per day	**232**	272	(15)	**216**	227	(5)

For the year ended March 31, 2013, oil production increased 26% to 28,028 bbls compared to 22,322 bbls last year due to new wells being produced on the Loon Block. Natural gas production for the year ended March 31, 2013, decreased 20% to 261,998 mcf compared to 326,047 mcf last year due to shutting in of gas wells as a result of low pricing and also increased suction pressure at the NEP facility at Leduc which effected solution gas production from the 8-32-49-26W4M battery. Natural gas liquids ("NGLs") increased 11% to 7,215 bbls during the year ended March 31, 2013 compared to 6,529 bbls last year. Total production expressed in boe for the year ended March 31, 2013, decreased 5% to 78,909 boe compared to 83,192 boe last year as Border was producing a higher weighted gas stream. Border has five key producing areas; Majeau, Norris, Red Earth Leduc and Pembina.

For the three months ended March 31, 2013, oil production increased 58% to 7,386 bbls compared to 4,671 bbls for the comparable period last year as the corporation brought on the 10-15-85-10W5M well and has completed pump optimization in Norris. Natural gas production for the three months ended March 31, 2013, decreased 42% to 62,366 mcf compared to 108,283 mcf for the comparable period last year due to continued shutting in of gas wells due to poor pricing and increased line pressure at the 8-32-49-26W4M battery. Natural gas liquids ("NGLs") increased 57% to 3,127 bbls during the three months ended March 31, 2013 compared to 1,991 bbls for the same period last year. Total production expressed in boe for the three months ended March 31, 2013, decreased 15% to 20,907 boe compared to 24,709 boe last year due to the gas weighting of total production.

PRICING SUMMARY

	THREE MONTHS ENDED MARCH 31 2013	THREE MONTHS ENDED MARCH 31 2012	% CHANGE	YEAR ENDED MARCH 31 2013	YEAR ENDED MARCH 31 2012	% CHANGE
Oil - $ per bbl	**$ 75.24**	$ 73.06	3	**$ 72.79**	$ 84.95	(14)
Natural gas liquids - $ per bbl	**$ 52.02**	$ 60.88	(15)	**$ 50.94**	$ 64.21	(21)
Natural Gas - $ per Mcf	**$ 3.13**	$ 2.27	38	**$ 2.68**	$ 3.10	(13)
$ per boe	**$ 43.70**	$ 28.65	53	**$ 39.42**	$ 39.97	(1)

During the year ended March 31, 2013, and the comparable period last year, Border sold all its oil, natural gas and natural gas liquids at spot prices and did not enter into any long-term, fixed price marketing contracts or derivative financial instruments. The Corporation's oil production is currently comprised of three different densities, classified as light, medium and heavy (844.2 to 949.1 kg/m3) and as such receives average prices that are lower than the light WTI spot price that is the most common oil reference price.

During the year ended March 31, 2013, the average realized boe price was $39.42 compared to $39.97 last year. Oil prices fell by 14% to average $72.79 per barrel from $$84.95 per barrel last year. Natural gas prices fell 13% to average $2.68 per mcf compared to $3.10 per mcf last year. Natural gas liquids fell 21% to average $50.94 per barrel from $64.21 per barrel last year. The percentage of natural gas production to oil and liquids production was 55% compared to 65% last year. The boe price will vary due to two key components, the first is the current market price of the products and the second is the Corporation's mix of products.
During the three months ended March 31, 2013, the average boe price was $43.70 compared to $28.65 last year. Oil prices increased by 3% to average $75.24 per barrel from $$73.06 per barrel last year.

Natural gas prices increased 38% to average $3.13 per mcf compared to $2.27 per mcf last year. Natural gas liquids fell 15% to average $52.02 per barrel from $60.88 per barrel last year. The percentage of natural gas production to oil and liquids production was 50% compared to 73% last year.

REVENUE

	THREE MONTHS ENDED MARCH 31 2013	THREE MONTHS ENDED MARCH 31 2012	% CHANGE	YEAR ENDED MARCH 31 2013	YEAR ENDED MARCH 31 2012	% CHANGE
Oil	**$ 555,709**	$ 341,263	63	**$ 2,040,190**	$ 1,896,144	8
Natural gas liquids	**162,670**	121,222	34	**367,517**	419,252	(12)
Natural Gas	**195,215**	245,416	(20)	**702,802**	1,009,548	(30)
Total Working Interest Revenue	**$ 913,594**	$ 707,901	29	**$ 3,110,509**	$ 3,324,944	(6)
$ per boe	**$ 43.70**	$ 28.65	53	**$ 39.42**	$ 39.97	(1)

Total revenue for the year ended March 31, 2013, decreased 6% or $214,435 totaling $3,110,509 compared to $3,324,944 last year due primarily to lower sales prices and lower natural gas sales volumes. Oil revenue increased by $144,046, or 8%, due to a 26% increase in oil sales volumes that was partially offset by a 14% decrease in the average oil sales price. Natural gas revenue fell by $306,746, or 30%, due to a 20% decrease in natural gas sales volumes and a 13% decrease in the average sales price. Natural gas liquids revenue fell by $51,735, or 12%, due to a 21% decrease in the average sales price that was partially offset by a 11% increase in sales volumes. Total revenue for the year ended March 31, 2013 when expressed as dollars per boe, fell 1% to average $39.42 per boe compared to $39.97 per boe last year.

Border Petroleum Corp.
Management's Discussion & Analysis

Total revenue for the three months ended March 31, 2013, increased 29% or $205,692 totaling $913,594 compared to $707,902 last year, due primarily to higher oil and natural gas liquids sales volumes and higher average oil prices. Oil revenue increased by $214,445, or 63%, due to a 58% increase in oil sales volumes and a 3% increase in the average oil price. Natural gas revenue fell by $50,201, or 20%, due to a 42% decrease in natural gas sales volumes that was partially offset by a 38% increase in the average gas price. Natural gas liquids revenue increased by $41,448 or 34%, due to a 57% increase in sales volumes that was partially offset by a 15% decrease in the average sale price. Total revenue for the three months ended March 31, 2013 when expressed as dollars per boe, increased 53% to average $43.70 per boe compared to $28.65 per boe last year.

ROYALTY SUMMARY

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	**2012**	**CHANGE**	**2013**	**2012**	**CHANGE**
Crown	**$ 34,958**	$ 1,329	2,530	**$ 79,025**	$ 103,527	(24)
Overriding and Freehold	**60,151**	40,764	48	**213,804**	164,682	30
Total Royalty Expense	**$ 95,109**	$ 42,093	126	**$ 292,829**	$ 268,209	9
$ per boe	**$ 4.55**	$ 1.70	167	**$ 3.71**	$ 3.22	15
Expense rate - % of total working interest revenue	**10**	6	67	**9**	8	13

Total royalties paid for the year ended March 31, 2013, increased by 9% to $292,829 compared to $268,209 paid last year. On a $ per boe basis, total royalties increased by 15% to $3.71 for the year ended March 31, 2013, compared to $3.22 per boe for last year. This royalty increase is the combination of two distinct categories of royalty costs incurred. As indicated in the table above, Crown royalties for the year ended March 31, 2013 have decreased 24% from last year, whereas the Overriding and freehold royalties have increased 30% this year compared to last year. Border's Crown royalties are primarily paid on the oil and natural gas sales from the Leduc area. This producing property was acquired through a merger with Canflame Energy Ltd. in July 2011 and since that time declining production and extremely low natural gas prices have impaired the development of this area, resulting in a decrease in Crown royalties.

The increase in Overriding and freehold royalties are primarily due to royalty payments to Indian Oil and Gas Company ("ÏOGC") for the new production from the horizontal wells in the Red Earth area completed in April and May 2012.

Total royalties paid for the three months ended March 31, 2013, increased by 126% to $95,109 compared to $42,093 for the same three months last year. Overriding and freehold royalties increased due primarily to greater fourth quarter production of the Red Earth and Norris wells. However, the Crown royalty increase was net of gas cost allowance credits which are based on annual forecasted production then adjusted to actual production annually. Without this adjustment, Crown royalties for the three months ended March 31, 2013 total $32,039, down 65% from the $90,284 paid in the three months ended March 31, 2012. This decrease is attributable to the decrease in production from the Leduc and Pembina area wells.

OPERATING AND TRANSPORTATION EXPENSES

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	**2012**	**CHANGE**	**2013**	**2012**	**CHANGE**
Production expenses	**$ 400,112**	$ 636,043	(37)	**$ 1,720,890**	$ 2,169,056	(21)
Transportation and gathering	**360,366**	119,398	202	**1,153,888**	361,426	219
	760,478	755,441	1	**2,874,778**	2,530,482	14
Workover expenses	**180,097**	69,988	157	**210,165**	176,289	19
Total Production Expenses	**$ 940,575**	$ 825,429	14	**$ 3,084,943**	$ 2,706,771	14
$ per boe Total production expenses	**$ 44.99**	$ 33.41	35	**$ 39.09**	$ 32.54	20
Production expenses	**$ 19.14**	$ 25.75	(26)	**$ 21.81**	$ 26.08	(16)
Transportation & gathering	**$ 17.24**	$ 4.83	257	**$ 14.62**	$ 4.34	237
Workover expenses	**$ 8.61**	$ 2.83	204	**$ 2.66**	$ 2.12	26
Expense rate - % of total working interest revenue	**103**	117	(12)	**99**	81	22

Total production expenses are comprised of three cost categories; day-to-day production expenses, transportation and gathering costs and work-over expenses. Production, transportation and gathering costs for the year ended March 31, 2013, increased 14% to total $2,874,778 compared to $2,530,482 last year. The transportation and gathering expense component of the production costs for the year ended March 31, 2013, increased 219% to $1,153,888 compared to $361,426 last year, due to trucking of produced water from the Leduc field, and increased production and water trucking for the testing of the 10-15-85-10W5M well in the Red Earth field which resulted in higher cost transportation arrangements. Total production expenses for the year ended March 31, 2013, increased 14% to $3,084,943 compared to $2,706,771 last year. When expressed as a $ per boe, total production expenses increased by 20% due primarily to higher transportation costs and a decrease in production volumes.

Day-to-day production, transportation and gathering costs for the quarter ended March 31, 2013, increased 1% to $760,478 compared to $755,441 for the same quarter last year. The transportation and gathering expense component of the production costs for the three months ended March 31, 2013, increased 202% to $360,366 compared to $119,398 for the same three months last year, due to trucking of produced water from the Leduc field, and increased production in the Red Earth field which resulted in higher cost transportation arrangements. Total production expenses for the three months ended March 31, 2013, increased 14% to $940,575 from $825,429 for the same three months last year due primarily to higher transportation costs. Workover expenses as a $ per boe during the quarter ended March 31, 2013, averaged $8.61 per boe increasing 204% from last year's average of $2.83 per boe due to the well servicing of several Norris wells.

GENERAL AND ADMINISTRATIVE EXPENSES

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	2012	CHANGE	2013	2012	CHANGE
General and administration	**$ 550,754**	$ 615,246	(10)	**$ 1,937,269**	$ 1,840,242	5
Transaction costs	**-**	100,001	(100)	**-**	394,604	(100)
	550,754	715,247	(23)	**1,937,269**	2,234,846	(13)
$ per boe	**$ 26.34**	$ 28.95	(9)	**$ 24.55**	$ 26.86	(9)
Expense rate - % of total working interest revenue	**60**	101	(40)	**62**	67	(7)

General and administrative expenses for the year ended March 31, 2013, increased by 5% totaling $1,937,269 compared to $1,840,242 last year. The additional "transaction costs" last year were legal fees and associated costs of $394,604 that were incurred due to the business combination with Canflame Energy Ltd. that closed on July 13, 2011.

General and administrative expenses for the quarter ended March 31, 2013, decreased by 10% totaling $550,754 compared to $615,246 for the same quarter last year. Additional legal fees and associated costs totaling $100,001 were incurred in the fourth quarter of last year due to the business combination with Canflame Energy Ltd. that closed on July 13, 2011.

FINANCE INCOME AND EXPENSES

Finance income, consisting of interest income, is recognized as it accrues in the statement of income, using the effective interest method. Finance expense comprises interest expense on convertible debentures and note payable and accretion on the convertible note payable and of decommissioning provisions.

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	2012	CHANGE	2013	2012	CHANGE
Finance income						
Interest income	**$ 96,018**	$ 74,599	29	**$ 229,327**	$ 183,758	25
	96,018	74,599	29	**229,327**	183,758	25
Finance expenses						
Interest expense	**13,756**	(333)	(4,231)	**28,074**	3,714	656
Interest expense on note payable	**-**	27,147	(100)	**63,594**	106,751	(40)
Accretion on convertible note payable	**7,747**	26,040	(70)	**74,135**	102,398	(28)
Accretion of decommissioning provisions	**6,645**	4,499	48	**24,522**	21,940	12
Asset retirement expenses - non-CGU	**18,655**	-	n/a	**18,716**	-	n/a
	46,803	57,353	(18)	**209,041**	234,803	(11)
Net finance income (expense)	**49,215**	17,246	185	**20,286**	(51,045)	(140)
Finance income (expense) cash items	**48,694**	177,502	(73)	**65,115**	180,044	(64)
Finance expense non-cash items	**521**	(160,256)	(100)	**(44,829)**	(231,089)	(81)
Net finance income (expense)	**49,215**	17,246	185	**20,286**	(51,045)	(140)
$ per boe - finance income (expense) cash items	**$ 2.33**	$ 7.18	(68)	**$ 0.83**	$ 2.16	(62)
$ per boe - finance expense non-cash items	**$ 0.02**	$ (6.49)	(100)	**$ (0.57)**	$ (2.78)	(79)
$ per boe - net finance income (expense)	**$ 2.35**	$ 0.69	241	**$ 0.26**	$ (0.62)	(142)

DEPLETION AND DEPRECIATION

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	2012	CHANGE	2013	2012	CHANGE
Depletion & depreciation	**$ 436,766**	$ 776,951	(44)	**$ 1,584,493**	$ 1,666,676	(5)
Impairment	**$ 13,480,946**	$ 9,817,656	37	**$ 13,480,946**	$ 9,817,656	37
	$ 13,917,712	$ 10,594,607	31	**$ 15,065,439**	$ 11,484,332	31
$ per boe - Depletion, depreciation	**$ 20.89**	$ 31.44	(34)	**$ 20.08**	$ 20.03	-
- Impairment	**$ 644.81**	$ 397.33	62	**$ 170.84**	$ 118.01	45
Expense rate - % of working interest revenue	**1,523**	1,497	2	**484**	345	40

Depletion and depreciation expense for the year ended March 31, 2013, totaled $1,584,493 or $20.08 per boe compared to $1,666,676 or $20.03 per boe for the same period last year. The depletion cost decreased 5% from the comparable period last year due to a corresponding 5% drop in barrels of equivalent production volumes.

Depletion and depreciation expense for the three months ended March 31, 2013, totaled $436,766 or $20.89 per boe compared to $776,951 or $31.44 per boe for the same period last year. The depletion cost per boe decreased 34% from the comparable period last year due primarily to last year’s fourth quarter downward adjustment to the developed and producing cost base caused by the $9.6 million impairment of the Leduc reserves at March 31, 2012.

During the three months ended March 31, 2013, the Corporation recorded impairment losses of $13,480,946 attributable to the Red Earth area Cost Generating Unit (CGU) and $8,333 to the Cardiff Area CGU.

The Red Earth impairment was the result of the three recently drilled horizontal wells in the Loon block which did not produce as forecasted in the March 2012 Sproule reserve report.
This year, the downward adjustment to the production curve together with the downward revision to Sproule’s future oil price estimates, resulted in a decrease of approximately 40% in the gross proved and probable reserve volumes for the Red Earth CGU from 1,444 Mboe at March 31, 2012 to 870 Mboe at March 31, 2013. Pursuant to IFRS guidelines, the impairment for the Red Earth CGU due to this volume revision, coupled with the forecasted price revisions in oil prices, was $13.5 million.

Cardiff impairment was due to the shutting in of the only well in the Cardiff CGU last year. Pursuant to IFRS guidelines, the impairment for the Cardiff CGU due to sundry land lease costs incurred this year was $8,333.

During the period ended March 31, 2013, $28,164,000 of future development costs related to proven and probable reserves were included in costs subject to depletion.

EXPLORATION AND EVALUATION EXPENDITURES

The Corporation recorded exploration and evaluation expenditures of $941,790 for the fourth quarter compared to $Nil for the respective period of 2012. During the year ended March 31, 2013, the Corporation expensed certain costs previously capitalized as exploration and evaluation assets as the lease term of undeveloped lands expired in the amount of $26,000 (2012 - $Nil) as well as $915,790 (2012 -$Nil) relating to its Montana, USA, assets as the Corporation had no plans to pursue development of these assets.

DEFERRED TAX RECOVERY

Deferred tax recovery was $168,719 in the fourth quarter and $1,393,304 for the year ended March 31, 2013 compared to a recovery of $960,000 and $994,415 in the respective periods of 2012, relating to the income tax recovery of flow-through share expenditures.

SHARE CAPITAL

Issued and Outstanding Common Shares

	March 31, 2013			March 31, 2012		
	Number	Stated Value		Number	Stated Value	
Balance, beginning of period	224,537,953	$	50,352,701	70,586,293	$	15,965,618
Issuance to acquire Canflame A&B shares (ii)	-		-	30,312,232		9,699,914
Issuance for Canflame debentures & accrued interest (ii)	-		-	6,225,594		1,992,190
Issuance of common shares (iii)	-		-	81,000,000		17,010,000
Issuance of flow-through shares (iii)	-		-	24,000,000		6,000,000
Issuance common shares (iv)	-		-	12,150,000		2,551,500
Flow-through share premium (iii)	-		-	-		(960,000)
Exercise of warrants (note 11(c))	-		-	263,834		50,675
Issuance common shares (i)	48,335,000		7,250,250	-		-
Issuance of flow-through shares (i)	60,106,000		10,750,830	-		-
Flow-through share premium (i)	-		(1,734,930)	-		-
Share issue costs (v)	-		(1,264,087)	-		(1,957,196)
	332,978,953	$	65,354,764	224,537,953	$	50,352,701

(i) On September 28, 2012, the Corporation closed a bought deal offering with a syndicate of Underwriters for the issuance of 48,335,000 common shares of the Corporation at a price of $0.15 per common share and 55,556,000 Canadian Exploration Expense ("CEE") flow-through shares of the Corporation at a price of $0.18 per flow-through share and 4,550,000 Canadian Development Expense ("CDE") flow-through shares of the Corporation at a price of $0.165 per flow-through share for aggregate gross proceeds of $18,001,080. The Underwriters were paid a cash commission of 6% of the gross proceeds of the offering.

Of the total proceeds from the flow-through shares issued, the premium paid for the flow-through shares of $1,734,930 was recorded as flow-through share premium. At December 31, 2012, the Corporation had incurred all of the CDE qualifying expenditures related to this issuance and accordingly, the flow-through share premium has been reversed through deferred income tax recovery. At March 31, 2013, the Corporation has incurred $7.9 million of the CEE qualifying expenditures related to this issuance and accordingly, the flow-through share premium related to the expenditures incurred has been reversed through deferred income tax recovery. An additional $2.1 million of CEE qualifying expenditures is required to be spent by December 31, 2013.

Prior Year Issuances

(ii) On July 13, 2011, the Corporation closed a business combination between a private, Alberta based oil and natural gas exploration and production company, Canflame Energy Ltd. ("Canflame") and a newly incorporated, wholly owned subsidiary of Border by way of an amalgamation (the "Transaction").

(iii) On November 30, 2011, the Corporation closed a bought deal offering with a syndicate of Underwriters for the issuance of 81,000,000 common shares of the Corporation at a price of $0.21 per common share and 24,000,000 flow-through shares of the Corporation at a price of $0.25 per flow-through share for aggregate gross proceeds of $23,010,000. The Underwriters were paid a cash commission of 6% of the gross proceeds of the offering and were granted broker warrants entitling the Underwriters to purchase 2,100,000 common shares of the Corporation equaling 2% of the number of common shares and flow-through shares sold under the offering at an exercise price of $0.21 per share for a period of 12 months from the closing of the offering. The fair value ascribed to the warrants for the units issued on November 30, 2011 and December 14, 2011 was $109,571 and $14,212, respectively. The fair value of the warrants was estimated based on the Black-Scholes option pricing model using an expected life of 1 year, a risk-free interest rate of 1.33%, expected dividends of $Nil, a forfeiture rate of Nil% and a volatility of 70% as underlying assumptions.

Of the total proceeds from the flow-through shares issued, the premium paid for the flow-through shares of $960,000 was recorded as flow-through share premium. At March 31, 2012, the Corporation had incurred all of the qualifying expenditures related to this issuance and accordingly, the flow-through share premium has been reversed through deferred income tax recovery.

(iv) On December 14, 2011, the Underwriters exercised the full Over-Allotment Option that they were granted with the offering, and purchased an additional 12,150,000 common shares at a price of $0.21 per common share for additional gross proceeds of up to $2,551,500. The Over-Allotment Option was issued on the same terms and conditions as the November 30, 2011 offering. The Underwriters received a fee of 6% of the gross proceeds of the Over-Allotment Option and compensation options entitling the Underwriters to purchase 243,000 Common Shares at an exercise price of $0.21 per share for a period of 12 months from the closing of the Over-Allotment Option.

(v) During the year ended March 31, 2013 and 2012, the Corporation incurred $1,264,087 (2012 - $1,833,413) of share issuance costs related to financings, which was further adjusted to reflect the valuation of Broker options of $Nil (2012 - $123,783) to total $1,264,087 (2012 - $1,957,196).

Warrants

	March 31, 2013		March 31, 2012	
	Number of Warrants	Weighted Average Exercise Price	Number of Warrants	Weighted Average Exercise Price
Outstanding, beginning of period	**16,506,666**	**$ 0.32**	14,427,500	$ 0.33
Issued (ii)	**-**	**-**	2,343,000	0.21
Exercised	**-**	**-**	(263,834)	0.19
Expired (i)	**(16,506,666)**	**0.32**	-	-
Outstanding and exercisable, end of period	**-**	**$ -**	16,506,666	$ 0.32

(i) During the year ended March 31, 2013, outstanding and exercisable warrants totaling 16,506,666 expired; leaving no outstanding warrants as at March 31, 2013.

(ii) Upon the closing of the bought deal offering, the Underwriters were paid a cash commission of 6% of the gross proceeds of the offering and were granted broker warrants entitling the Underwriters to purchase 2,100,000 common shares of the Corporation equaling 2% of the number of common shares and flow-through shares sold under the offering at an exercise price of $0.21 per share for a period of 12 months from the closing of the offering. On December 14, 2011, the Underwriters received a fee of 6% of the gross proceeds of the Over-Allotment Option and compensation options entitling the Underwriters to purchase 243,000 Common Shares at an exercise price of $0.21 per share for a period of 12 months from the closing of the Over-Allotment Option.

STOCK BASED COMPENSATION

	March 31, 2013		March 31, 2012	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Outstanding, beginning of period	14,936,250	$0.23	2,923,750	$0.25
Cancelled or expired	(311,250)		(537,500)	$0.25
	14,625,000	$0.23	2,386,250	$0.25
Granted	-	-	12,550,000	$0.23
Exercised	-	-	-	-
Outstanding, end of period	14,625,000	$0.23	14,936,250	$0.23
Exercisable, end of period	6,408,334	$0.23	1,865,417	$0.26

The Corporation has established a stock option plan (the "Plan") which is administered by the Board of Directors, allowing the Board of Directors to grant stock options. The Plan allows for the granting of stock options for the purchase of up to 10% of the outstanding common shares of the Corporation.
Options may not be granted to any one person, any one consultant or any persons performing investor relations duties in any twelve month period which could, when exercised, result in the issuance of shares exceeding 5%, 2% or 2%, respectively, of the issued and outstanding common shares of the Corporation. All options granted under the Plan shall expire as determined by the Board of Directors not later than the tenth anniversary of the date the options were granted.

The exercise price of the options is to be determined by the Board of Directors, but shall not be less than the market price of the common shares of the Corporation on the TSXV on the last business day before the date on which the options are granted, less any discount permitted by the rules of the TSXV. Vesting of the options is at the discretion of the Board of Directors but generally will occur over a two to three year period following the grant date.

As at March 31, 2013, the Corporation had 14,625,000 stock options outstanding with a weighted average exercise price of $0.23 and 6,408,334 of these stock options were exercisable at a weighted average price of $0.23. There were no stock options granted during the year ended March 31, 2013. As at March 31, 2012, the Corporation had 14,936,250 stock options outstanding with a weighted average exercise price of $0.23 and 1,865,417 of these stock options were exercisable at a weighted average price of $0.26.

Compensation costs of $885,719 for the year ended March 31, 2013, (2012 - $410,314) have been expensed and have resulted in a corresponding increase in contributed surplus.

	THREE MONTHS ENDED MARCH 31 2013	THREE MONTHS ENDED MARCH 31 2012	% CHANGE	YEAR ENDED MARCH 31 2013	YEAR ENDED MARCH 31 2012	% CHANGE
Stock based compensation	**$ 105,495**	$ 266,036	(60)	**$ 885,719**	$ 410,314	116
$ per boe	**$ 5.05**	$ 10.77	(53)	**$ 11.22**	$ 4.93	128
Expense rate - % of working interest revenue	**12**	38	(70)	**28**	12	130

Stock-based compensation for the year ended March 31, 2013 was $885,719 or $11.22 per boe, compared to $410,314 or $4.93 per boe for last year.
The Corporation calculates stock-based compensation using the Black-Scholes option-pricing model. For the year ended March 31, 2013, no new options were granted and 311,250 options were cancelled or expired. At March 31, 2013, there were 6,408,334 options that were exercisable.

AVERAGE SHARES OUTSTANDING

The weighted average number of shares outstanding for the year ended March 31, 2013, totaled 279,204,101 compared to 135,394,501 for the year ended March 31, 2012.

Border Petroleum Corp.
Management's Discussion & Analysis

Common shares and other equity instruments outstanding as at the date of this MD&A is as follows:

Common shares	332,978,953
Stock options	14,625,000

NET LOSS AND COMPREHENSIVE LOSS

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	2012	CHANGE	2013	2012	CHANGE
Net income (loss) for period	**$ (15,419,907)**	$ (10,758,266)	43	**$ (17,683,890)**	$ (12,836,158)	38
Income (Loss) per share	**$ (0.06)**	$ (0.08)	(30)	**$ (0.06)**	$ (0.09)	(33)

A net loss and comprehensive loss of ($17,683,890) was recorded for the year ended March 31, 2013, compared to a net loss and comprehensive loss of ($12,836,158) last year. This was due primarily to lower sales volumes, higher operating costs, an increase in stock-based compensation and the impairment loss.

NET PETROLEUM AND NATURAL GAS REVENUE

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	2012	CHANGE	2013	2012	CHANGE
Petroleum & Natural Gas Revenue	**$ 913,594**	$ 707,901	29	**$ 3,110,509**	$ 3,324,944	(6)
Less:						
Royalties	**95,109**	42,093	126	**292,829**	268,209	9
Production expenses	**760,478**	755,441	1	**2,874,778**	2,530,482	14
Workover expenses	**180,097**	69,988	157	**210,165**	176,289	19
Net Petroleum & Natural Gas Revenue	**$ (122,090)**	$ (159,621)	(24)	**$ (267,263)**	$ 349,964	176
$ per boe	**$ (5.84)**	$ (6.46)	(9)	**$ (3.38)**	$ 4.21	180

Gross revenue from petroleum and natural gas decreased 6% to total $3,110,509 for the year ended March 31, 2013, compared to $3,324,944 last year. The net petroleum and natural gas losses after royalties, production and workover expenses for the year ended March 31, 2013 was ($267,263) compared to net petroleum and natural gas revenue of 349,964 last year.

Gross revenue from petroleum and natural gas increased 29% to total $913,594 for the three months ended March 31, 2013, compared to $707,902 last year. Net petroleum and natural gas losses after royalties, production and workover expenses for the three months ended March 31, 2013 decreased 24% to ($122,090) compared to net petroleum and natural gas losses of ($159,621) last year.

NETBACKS

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	**2012**	**CHANGE**	**2013**	**2012**	**CHANGE**
$ per boe						
Working Interest Revenue	**$ 43.70**	$ 28.65	53	**$ 39.42**	$ 39.97	(1)
Royalties	**4.55**	1.70	168	**3.71**	3.22	15
Production expense	**19.14**	25.75	(26)	**21.81**	26.08	(16)
Gather/transportation	**17.24**	4.83	257	**14.62**	4.34	237
Workover expenses	**8.61**	2.83	204	**2.66**	2.12	25
Total after royalties and production expenses	**$ (5.84)**	$ (6.46)	(9)	**$ (3.38)**	$ 4.21	(180)
General and administration and transaction costs	**26.34**	28.95	(9)	**24.55**	26.86	(9)
Finance income cash items	**2.33**	7.18	(68)	**0.83**	2.16	(62)
Total Corporate Netbacks	**$ (29.85)**	$ (28.23)	6	**$ (27.10)**	$ (20.49)	32
Non-Cash Items						
Depletion, depreciation and accretion	**20.89**	31.44	(34)	**20.08**	20.03	-
Exploration and evaluation expense	**45.05**	-	-	**11.93**	-	-
Impairment loss	**644.80**	397.32	62	**170.86**	118.02	45
Stock based compensation	**5.05**	10.77	(53)	**11.22**	4.93	128
Finance expense non-cash items	**0.02**	(6.49)	(100)	**(0.57)**	(2.78)	(79)
Deferred tax expense (recovery)	**(8.07)**	**(38.85)**	-	**(17.66)**	(11.95)	48
Total Netbacks after non-cash items (*)	**$ (737.55)**	$ (435.40)	69	**$ (224.10)**	$ (154.30)	45

(*) totals may not add due to rounding

Field netback for the year ended March 31, 2013, was a loss of ($3.38) per boe compared to a gain of $4.21 per boe last year. Total netbacks after non-cash items for the year ended March 31, 2013, were losses of ($212.50) per boe compared to ($154.30) per boe last year.

Field netback for the three months ended March 31, 2013, was a loss of ($5.84) per boe compared to a loss of ($6.46) per boe for the comparable period last year. Total netbacks after non-cash items for the three months ended March 31, 2013, was a loss of ($693.74) per boe compared to the loss of ($435.40) per boe for the comparable period last year.

CAPITAL ADDITIONS

	THREE MONTHS ENDED MARCH 31		%	YEAR ENDED MARCH 31		%
	2013	**2012**	**CHANGE**	**2013**	**2012**	**CHANGE**
Exploration and evaluation assets	**$ 73,309**	$ (284,899)	(126)	**$ 572,533**	$ 4,388,106	(87)
Property and equipment						
Land and lease costs	**(134,060)**	-	n/a	**323,705**	-	n/a
Geophysical and seismic	**131,709**	-	n/a	**197,439**	-	n/a
Drilling and completions	**740,199**	7,245,914	(90)	**9,413,919**	10,078,271	(7)
Production equipment and facilities	**(64,091)**	1,533,031	(104)	**1,001,751**	2,262,641	(56)
Property acquisitions	**-**	-	n/a	**54,907**	17,326,419	(100)
Asset retirement	**300,234**	174,995	n/a	**411,405**	304,653	n/a
Furniture & computers	**-**	(7,055)	(100)	**8,581**	17,249	(50)
Total	**$ 1,047,300**	$ 8,661,986	(88)	**$ 11,984,240**	$ 34,377,339	(65)

Total asset additions were $11,984,240 for the year ended March 31, 2013, compared to $34,377,339 last year. Capital additions last year included the acquisition of Canflame Energy Ltd and the Leduc farm-in purchase. See details in Note 4 of the current financial statements. These additions included $ 411,405 of asset retirement decommissioning adjustments.

The additions to capital expenditures during the year ended March 31, 2013 relate primarily to the drilling, completion and equipping of the long-leg horizontal Red Earth well drilled during December 2012 and the completion and equipping of the two short-leg Red Earth horizontal wells drilled in March 2012.

BANK DEBT

The Corporation has no bank debt outstanding under a demand revolving operating loan at March 31, 2013, (March 31, 2012 - $Nil). This facility provides that advances be made by way of prime-based loans and letters of credit to an aggregate maximum of $3,500,000. The facility bears interest of prime plus 1.25% per annum on prime-based loans and 2.00% per annum with a minimum fee of $200 for letters of credit. There is also a non-refundable facility fee calculated at a rate of 0.25% per annum, payable monthly, calculated on the unused portion of the authorized amount of this facility.

Under the terms of the credit facility, the Corporation must maintain a working capital ratio no less than 1:1 adjusted for any un-drawn portion of the revolving facility and excluding the mark to market impact of forward commodity contracts, if applicable.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2013, Border had working capital (current assets minus current liabilities) of $7,519,842 (excluding flow-through share premium) compared to working capital of $6,217,603 at March 31, 2012.

	MARCH 31 2013	MARCH 31 2012	% CHANGE
Cash	**$ 8,266,710**	$12,972,419	(36)
Accounts receivable and prepaid expenses	**1,496,577**	1,557,612	(4)
Investment in secured debt	**899,067**	762,929	18
Accounts payable and accrued liablities	**(3,142,512)**	(9,075,357)	(65)
	$ 7,519,842	$ 6,217,603	21

Pursuant to its joint venture with the Loon River Cree Nation, as well as its current land holdings at its Red Earth core areas, Border has a significant drilling portfolio.

The Corporation has a credit facility for a demand revolving operating loan of $3,500,000. At March 31, 2013, the Corporation had not drawn on the credit facility.

On September 28, 2012, the Corporation closed a bought deal offering with a syndicate of Underwriters for the issuance of 48,335,000 common shares of the Corporation at a price of $0.15 per common share and 55,556,000 Canadian Exploration Expense (“CEE”) flow-through shares of the Corporation at a price of $0.18 per flow-through share and 4,550,000 Canadian Development Expense (“CDE”) flow-through shares of the Corporation at a price of $0.165 per flow-through share for aggregate gross proceeds of $18,001,080. The Underwriters were paid a cash commission of 6% of the gross proceeds of the offering.

Of the total proceeds from the flow-through shares issued, the premium paid for the flow-through shares of $1,734,930 was recorded as flow-through share premium. At December 31, 2012, the Corporation had incurred all of the CDE qualifying expenditures related to this issuance and accordingly, the flow-through share premium has been reversed through deferred income tax recovery. At March 31, 2013, the Corporation has incurred $7.9 million of the CEE qualifying expenditures related to this issuance and accordingly, the flow-through share premium related to the expenditures incurred has been reversed through deferred income tax recovery. An additional $2.1 million of CEE qualifying expenditures is required to be spent by December 31, 2013.

OFF-BALANCE SHEET ARRANGEMENTS

The Corporation has no off-balance sheet arrangements.

TRANSACTIONS WITH RELATED PARTIES

The Corporation utilizes the services of a law firm in which a Director of the Corporation is a Partner. During the year ended March 31, 2013, the Corporation incurred $129,160 (2012 - $291,478) on legal services, of which $50,581 (2012 - $193,705) is included in general and administrative expense or transaction costs, $78,579 (2012 - $97,773) is included in share issuance costs and $2,151 (2012 - $5,686) is included in accounts payable and accrued liabilities.

COMMITMENTS AND CONTINGENCIES

(a) Flow-through share commitment

Pursuant to the Corporation's flow-through financing in September 2012, the Corporation is required to spend $750,750 of qualifying oil and natural gas development costs (“CDE”) by December 31, 2012, and $10,000,080 of qualifying oil and natural gas exploration costs (“CEE”) by December 31, 2013. At March 31, 2013 the Corporation had incurred $750,750 on qualifying CDE expenditures and $7,950,326 CEE expenditures toward fulfilling these flow-through share spending commitments.

(b) Contingent acquisition costs

During the year ended March 31, 2011, the Corporation entered into a termination agreement pertaining to an Area of Mutual Interest ("AMI") and Farm-in Agreement dated July 1, 2009 (the “Termination Agreement”). By Termination Agreement dated November 1, 2010, the parties terminated the Area of Mutual Interest Agreement and set out terms for payment by Border. Border is required to pay twenty percent of net monthly revenue (net of royalties, overriding royalties, transportation and processing fees) received from the current and future re-entries conducted by Border on the lands previously covered by the "AMI" at the end of each month to a total maximum payment of all payments under the agreement of $550,000.

For the year ended March 31, 2013 total cash payments of $32,250 (2012 - $100,708) have been paid and an additional $34,386 (2012 - $66,727) has been accrued for the year ending March 31, 2013 based on management's estimate of the amount that will ultimately be paid under the Termination Agreement.

(c) Legal matters

Canflame, now amalgamated with a wholly-owned subsidiary of the Corporation, has been named as a defendant in a lawsuit on behalf of a joint venture partner seeking to recover damages allegedly sustained by them as a result of a breach of agreement. The complaint with respect to this action generally alleges Canflame failed to pay certain AFEs. Canflame has also filed a counterclaim. These lawsuits remain at an early stage and management has determined that the likelihood of any loss occurring as being remote and has accrued no amounts related to this claim at March 31, 2013 (see note 4).

(d) Office Lease

The Corporation entered into a commitment related to the leasing of office premises. The payments due including estimated operating costs are as follows:

Office Premises	- 2014	$	225,792
	- 2015		150,528
		$	376,320

SUBSEQUENT EVENTS

The Corporation has formed a Special Committee of independent directors and has initiated a strategic review process to identify, examine and consider a range of strategic alternatives available to Border, with a view to maximizing shareholder value. This process could result in a sale of the Corporation, a sale of a material portion of the Corporation's assets, a merger, business combination or a corporate reorganization, among other alternatives.

RISK FACTORS

The following are certain risk factors that relate to Border that the reader should consider. If any event arising from these factors occurs, the Corporation's business could be materially affected.

- Fluctuations in the prices of oil and gas will affect Border's revenue, cash flows and earnings and the value of the Corporation's oil and gas properties. These fluctuations could also affect the Corporation's ability to raise capital. These fluctuations in prices could be due to global economic and market conditions, weather conditions, the level of consumer and industrial demand, and governmental regulations.

- Drilling activities are subject to risks such as the possibility that commercially productive reservoirs will not be encountered, weather conditions, the ability to obtain regulatory approvals and shortages or delays in equipment and services.

- Estimates of oil and natural gas reserves involve a great measure of uncertainty as they depend on the reliability of available data, the costs to recover said reserves, and the ability to transport the product to market.

- There are operating risks that could affect the business of the Corporation. These include blowouts, equipment failures, spills or leaks, accidents and weather conditions.

- Compliance with and changes to environmental laws and regulations.

- The oil and gas industry is extremely competitive.

- The value of the Corporation's oil and gas properties.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Corporation has not entered into any marketing arrangements related to the selling of oil or natural gas production.

Fair Values

The fair values of cash, accounts receivable, deposits, investment in secured debt, bank debt and accounts payable and accrued liabilities approximate their carrying value.

At March 31, 2013, the Corporation does not have any financial derivatives, including commodity contracts. Consequently, the Corporation's financial instruments were recorded at fair value on the balance sheet with changes to fair value being reported in the statement of loss and comprehensive loss.

The fair value of transactions are classified according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities.

- Level 2 – Inputs are other than quoted prices in Level 1 that are either directly or indirectly observable for the asset or liability.

- Level 3 – Inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

The Corporation's cash has been valued using Level 1 inputs.

The Corporation is exposed to financial risks arising from its financial assets and liabilities. The Corporation manages its exposure to financial risks by operating in a manner that minimizes its exposure to the extent practical. The main financial risks affecting the Corporation are as follows:

Credit Risk

Credit risk is primarily related to the Corporation's receivables from oil and natural gas marketers and joint interest partners and the risk of financial loss if a customer, partner, or counterparty to a financial instrument fails to meet its contractual obligations. Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following production. Currently the Corporation sells the majority of its production to an oil and gas marketer. The Corporation historically has not experienced any collection issues with its oil and natural gas marketers. Joint interest partner receivables are typically collected within one to three-months of the joint venture bill being issued to the partner.

The Corporation attempts to mitigate the risk from joint interest partners' receivables by obtaining partner approval of significant capital expenditures prior to expenditure. The Corporation does not typically obtain collateral from joint interest partners; however, in certain circumstances, it may cash-call a partner in advance of the work and as well the Corporation has the ability in most cases to withhold production from joint interest partners in the event of non-payment. The Corporation establishes an allowance for doubtful accounts as determined by management based on their assessed collectability; therefore, the carrying amount of accounts receivable generally represents the maximum credit exposure.

The Corporation believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business. There were no receivables allowed for or written off during the year ended March 31, 2013 and there is $469,308 (2012 - $595,949) in accounts receivable outstanding greater than 90 days at March 31, 2013, which the Corporation would consider past due under normal conditions. Of this balance, $401,836 (2012 - $330,202) is due from one joint venture partner.

Cash balances consist of amounts on deposit with banks and term deposits. The Corporation manages the credit exposure of cash by selecting financial institutions with high credit ratings.

Total credit risk at March 31, 2013, is comprised of $1,394,733 in accounts receivable, $101,844 in deposits and prepaid expenses, $150,422 in lease reclamation deposits, $899,067 in investment in secured debt and $8,266,710 in cash and cash equivalents.

Market Risk

Market risk consists of commodity price, foreign exchange and interest rate risk, that may affect the value of the Corporation's financial instruments.

Commodity Price Risk

Commodity price risk is the risk that the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by the world and continental/regional economy and other events that dictate the levels of supply and demand. The Corporation has not attempted to mitigate commodity price risk through the use of financial derivative contracts. The Corporation had no financial derivative sales contracts or working capital items denominated in foreign currencies as at or during the year ended March 31, 2013.

Foreign Currency Exchange Risk

Foreign currency exchange risk is the risk that future cash flows will fluctuate as a result of changes in foreign exchange rates. Although all the Corporation's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian dollar and the United States dollars. The Corporation had no forward exchange rate contracts in place as at or during the year ended March 31, 2013.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate price risk to the extent that the investment in secured debt and term deposits both bear interest at a fixed rate and interest rate cash flow risk to the extent that bank debt, if any, bears interest at a floating rate.

Operational Risks

Border's operational activities are focused in the Western Canadian Sedimentary Basin, a competitive environment with a number of companies exploring for hydrocarbons. Other operational risks include weather delays, mechanical or technical difficulties, and exploration risks associated with finding economically viable hydrocarbons reserves. Border attempts to manage these risks by maintaining an inventory of certain critical equipment; conducting advance planning to manage its drilling programs in an efficient and cost effective manner; and hiring experienced technical staff and personnel to conduct its exploration programs.

Border's field operations are also subject to health, safety and environmental risks. The Corporation maintains a Health, Safety and Environmental Policy and an Emergency Response Plan which are updated bi-annually or as needed to comply with current legislation. Both are designed to protect the health and safety of all concerned property, drilling, pollution, and commercial general liability.

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they are due. The Corporation's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due without incurring unacceptable losses or risking harm to the Corporation's reputation. The Corporation prepares capital expenditure budgets which are regularly monitored and updated as considered necessary. As well, the Corporation utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. Also see below for a discussion on the Corporation's capital management policy.

Capital Management

The Corporation's policy is to maintain a strong capital base with the following objectives:

- Maintaining financial flexibility
- Maintaining creditor and investor confidence, and
- Sustaining the future development of the business.

The Corporation manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. Working capital (excluding flow-through share premium) and debt instruments (if any) are the components of the Corporation's capital structure to be managed. The most significant alternatives available for the management of the capital structure include adjusting capital spending to manage projected debt levels or to issue common shares or debentures when management and the Board of Directors feel the timing is appropriate. Management continually monitors the Corporation's projected capital spending and its net debt to maintain a sound capital position. Refer to the above section "Liquidity and Capital Resources".

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by Border are disclosed in notes 2 and 3 to the financial statements for the year ended March 31, 2013. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstance may result in actual results or changes to estimate amounts that differ materially from current estimates. The following discussion helps to assess the critical accounting policies and practices of the Corporation and the likelihood of materially different results from those reported.

Proved Reserves

Under National Instrument 51-101 "Proved" reserves are defined as those reserves that can be estimated with a high degree of certainty to be recoverable. The level of certainty should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved reserves.

It does not mean that there is a 90 percent probability that the Proved reserves will be recovered – it means there must be at least a 90 percent probability that the given amount or more will be recovered.

"Proved plus Probable" reserves are the most likely case and are based on a 50 percent certainty that they will equal or exceed the reserves estimated. The standard provides for a conservative evaluation of proved and probable reserves, particularly on new wells where production history has not yet been established.

These oil and gas reserve estimates are made using all available geological and reservoir data, as well as historical production data. Estimates are reviewed on a quarterly basis and revised as appropriate. Revisions occur as a result of various factors including: actual reservoir performance, changes in price and cost forecasts or a change in the Corporation's plans. Reserve changes will impact the financial results as reserves are used in the calculation of depletion and are used to assess whether asset impairment occurs. Reserve changes also affect other Non-IFRS measures such as finding and development costs; recycle ratios and net asset value calculations.

Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and judgments are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Accounting estimates will, by definition, seldom equal the actual results. Revisions to accounting estimates are recognized in the periods in which the estimates are revised and in any future years affected.

The following discussion sets forth management's most critical estimates and assumptions in determining the value of assets, liabilities and equity:

Depletion and depreciation and valuation of property and equipment and exploration and evaluation assets

The amounts recorded for depletion and depreciation of property and equipment and the valuation of property and equipment are based on estimates. These estimates include proved and probable reserves, production rates, future oil and natural gas prices, future development costs, remaining lives and periods of future benefits of the related assets and other relevant assumptions.

The Corporation's reserve estimates are evaluated annually pursuant to the parameters and guidelines stipulated under *National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities*.

The valuation of exploration and evaluation assets is dependent upon the discovery of economically recoverable reserves which in turn is dependent on future oil and natural gas prices, future capital expenditures and environmental and regulatory restrictions.

The decision to transfer assets from exploration and evaluation assets to property and equipment is based on the estimated proved and probable reserves which are in part used to determine a project's technical feasibility and commercial viability.

For impairment testing, property and equipment and exploration and evaluation assets are aggregated into cash generating units ("CGUs"), based on management's judgment in defining the smallest identifiable group of assets that generate cash inflows that are largely independent of the cash flows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

Decommissioning provisions

The value of decommissioning provisions depends on estimates of current risk-free interest rates, future restoration and reclamation expenditures and the timing of those expenditures.

Valuation of accounts receivable

The valuation of accounts receivable is based on management's best estimate of the provision for doubtful accounts.

Income taxes

The amounts recorded for deferred income taxes are based on estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted. They are also based on estimates of the probability of the Corporation utilizing certain tax pools and assets which, in turn, is dependent on estimates of proved and probable reserves, production rates, future petroleum and natural gas prices and changes in legislation, tax rates and interpretations by taxation authorities. The availability of tax pools is subject to audit and interpretation by taxation authorities.

Stock-based compensation

The amounts recorded relating to the fair value of stock options and warrants granted are based on estimates of the future volatility of the Corporation’s share price, expected lives of the options and warrants, expected forfeiture rates, expected dividends and other relevant assumptions.

Investment in secured debt

The amount recorded for investment in secured debt and the valuation thereof is based on management’s assessment of the value of the underlying assets held as security. The classification of investment in secured debt as a current or non-current asset is based on management's estimate on timing of collection of amounts outstanding.

Contingent acquisition costs

The amount accrued for contingent consideration payable under a land acquisition (note 20(b)) is based upon estimates of proved reserves and future oil and natural gas prices and related transportation and processing costs.

Business combination

The values assigned to the common shares issued in the corporate acquisition completed in fiscal 2012 and the allocation of the purchase price to the net assets in the acquisition are based on numerous estimates that affect the valuation of certain assets and liabilities acquired including discount rates, estimates of proved and probable reserves, estimates of fair values of exploration and evaluation assets, future oil and natural gas prices and other factors.

The number of common shares issued on the business combination and the associated consideration paid are dependent upon management's best estimate of the resolution of the pre-existing legal action.

Convertible note payable

The allocation between the debt and equity components of the convertible note payable is based on estimates of the interest rate the Corporation would pay on a non-convertible note payable with similar terms.

CHANGES IN ACCOUNTING POLICIES AND NEW ACCOUNTING PRONOUNCEMENTS

Recent Accounting Pronouncements

Accounting standards and amendments to existing standards not yet affective

The Corporation has reviewed new and revised accounting standards that have been issued but are not yet effective, and determined that the following may have an impact on the Corporation:

For the annual periods beginning on or after January 1, 2013, the Corporation will be required to adopt the following:

- IFRS 7, "Financial Instruments" provides additional information about offsetting of financial assets and liabilities. Additional disclosures will be required to enable users of financial statements to evaluate the effect or potential effect of netting arrangements on the entity's financial position.

- IFRS 10, "Consolidated Financial Statements" provides a single model to be applied in control analysis for all investees including special purpose entities.

- IFRS 11, "Joint Arrangements" redefines joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint operations will need to be proportionately consolidated and joint ventures to be equity accounted.

- IFRS 12, "Disclosure of Interests in Other Entities" combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities.

- IFRS 13, "Fair Value Measurement" defines the fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

In addition to the issuance of new standards as detailed above, there have also been amendments to existing standards, which are also effective January 1, 2013, including:

- IAS 1, "Presentation of Financial Statements" amended to require presentation of an additional opening balance sheet when an entity applies an accounting policy retrospectively or makes a retrospective restatement or reclassification and to clarify the disclosure requirements.

- IAS 32, "Financial Instruments: Presentation" amended to clarify the criteria that should be considered in determining whether an entity has a legally enforceable right of offset in respect of its financial instruments and clarifying the treatment of income taxes related to distributions and transaction costs.

For annual periods beginning on or after January 1, 2015, the Corporation will be required to adopt:

- IFRS 9, "Financial Instruments" - the new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

The Corporation has not yet completed its assessment and evaluation of the effect of adopting the new and amended standards and the impact it may have on its financial statements.

BUSINESS RISKS AND UNCERTAINTIES

Border advises readers that this Report may contain a number of forward-looking statements that involve a number of risks and uncertainties. Such information, although considered reasonable by Border at the time, may ultimately prove incorrect, too optimistic or too pessimistic, and actual results may differ materially from those anticipated in the statements. For this purpose, any statements contained within this Report that are not statements of historical fact may be deemed forward looking.

In common with all public oil and gas companies, and especially smaller companies, Border is subject to considerable market volatility affecting the prices received for its production, foreign exchange and interest rates, the availability and cost of capital financing, and market liquidity for its common shares. Furthermore, high energy prices can lead to increased energy supplies, reduced economic activity, and increased conservation efforts, which then sow the seeds for lower energy prices. Border does not participate in hedging of oil and gas prices, foreign exchange or interest rates, as it considers such activities to be highly risky and a distraction from its primary areas of focus.

The oil and gas business is also subject to a number of operational risks and uncertainties relating to such matters as exploration and development success, technical drilling and production performance and equipment failure including blowouts and fires, reserve recovery rates and timing, availability of third-party natural gas transportation, environmental damage and competition with much larger and better-financed companies for scarce land, people and financial resources.

To manage these risks and uncertainties, Border relies upon the expertise and creativity of its human resources, the development of strategic relationships with industry partners, modern exploration, engineering and business technology, professional environmental sensitivity assessments, and public liability, property damage and business interruption insurance.

Furthermore, the oil and gas industry is subject to extensive regulatory environments and fiscal regimes, both in Canada and internationally, which are subject to changes and beyond the control of the Corporation. The Corporation takes a proactive approach with respect to environment and safety. An operational emergency and response plan and safety policy are in place and the Corporation is in compliance with current environmental legislation.

DATE

This Management Discussion and Analysis is dated as of July 26, 2013.

ADDITIONAL INFORMATION

Additional information regarding Border is available on SEDAR at www.sedar.com.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbls	Barrels
Mbbls	thousand barrels
bbls/d	barrels of oil per day
boe/d	barrels of oil equivalent per day
NGLs	natural gas liquids (consisting of any one or more of propane, butane and condensate thousand stock tank barrels of oil
bpd	barrels of production per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
m3	cubic meters

Other

boe means barrels of oil equivalent. A barrel of oil equivalent is determined by converting a volume of natural gas to barrels using the ration of six (6) mcf to one (1) barrel. “boe” may be misleading, particularly if used in isolation the boe conversion ration of six (6) mcf: one (1) bbl is based on an energy equivalency methods primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

GORR means gross overriding royalty

CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic meters	28.174
cubic meters	Cubic feet	35.494
bbls	Cubic meters	0.159
feet	meters	0.305
acres	hectares	0.405

SUMMARY OF QUARTERLY RESULTS

The Corporation's results of operations for the eight most recent fiscal quarters are summarized as follows:

	THREE MONTHS ENDED MAR 31/2013	THREE MONTHS ENDED DEC 31/2012	THREE MONTHS ENDED SEPT 30/2012	THREE MONTHS ENDED JUN 30/2012
	Q4	Q3	Q2	Q1
Total Production Volumes				
Natural gas (Mcf)	62,366	67,152	56,705	75,775
Oil and NGL (bbl)	10,513	8,193	6,975	9,562
Combined (boe)	20,907	19,385	16,426	22,191
Daily Production				
Natural gas (Mcf per day)	693	730	616	833
Oil and NGL (bbl per day)	117	89	76	105
Combined (boe per day)	232	211	179	244
Gross Revenue				
Natural Gas	$ 195,215	$ 216,244	$ 132,145	$ 159,198
Oil and liquids	718,379	514,106	483,265	691,957
Total PNG Revenue	913,594	730,350	615,410	851,155
Royalty Expense				
Crown royalties	34,958	17,701	(304)	26,670
Freehold and overriding royalties	60,151	66,325	22,356	64,972
Total Royalty Expense	$ 95,109	$ 84,026	$ 22,052	$ 91,642
Net Revenue after Royalties	**$ 818,485**	**$ 646,324**	**$ 593,358**	**$ 759,513**
Operating, transportation & workover	940,575	551,609	613,551	979,206
General and administrative	550,754	443,173	478,566	464,776
Transaction costs	-	-	-	-
Stock based compensation	105,495	257,304	261,205	261,715
Depletion and depreciation	436,766	386,101	328,788	432,838
Exploration and evaluation expense	941,790			
Impairment	13,480,946			
Income (loss) before finance expense and income taxes	$ (15,637,841)	$ (991,863)	$ (1,088,752)	$ (1,379,022)
Net finance (income) expense	$ 49,215	$ (3,879)	$ (6,728)	$ (18,322)
Deferred income tax recovery	(168,719)	(1,224,585)	-	-
Net and Comprehensive Loss	**$ (15,419,907)**	**$ 228,843**	**$ (1,095,480)**	**$ (1,397,344)**
Basic income (loss) per share	($0.06)	$0.00	($0.01)	($0.01)
Average Price				
Natural gas ($ per Mcf)	$ 3.13	$ 3.22	$ 2.33	$ 2.10
Oil and NGL ($ per bbl)	$ 68.33	$ 62.75	$ 69.29	$ 72.37
$ per boe	$ 43.70	$ 37.68	$ 37.47	$ 38.36
Total Assets	**$ 33,857,436**	**$ 54,799,601**	**$ 49,817,051**	**$ 36,246,204**
Total Liabilities	**$ 5,688,908**	**$ 11,294,161**	**$ 6,795,386**	**$ 7,417,197**

Border Petroleum Corp.
Management's Discussion & Analysis

SUMMARY OF QUARTERLY RESULTS – continued

	THREE MONTHS ENDED MAR 31/2012	THREE MONTHS ENDED DEC 31/2011	THREE MONTHS ENDED SEPT 30/2011	THREE MONTHS ENDED JUN 30/2011
	Q4	**Q3**	**Q2**	**Q1**
Total Production Volumes				
Natural gas (Mcf)	108,283	132,040	83,296	2,428
Oil and NGL (bbl)	6,662	12,084	7,826	2,279
Combined (boe)	24,709	34,091	21,708	2,684
Daily Production				
Natural gas (Mcf per day)	1,190	1,435	905	27
Oil and NGL (bbl perday)	73	131	85	25
Combined (boe per day)	272	371	236	29
Gross Revenue				
Natural Gas	$ 245,416	$ 441,222	$ 312,657	$ 10,253
Oil and liquids	462,485	1,060,230	560,719	231,963
Total PNG Revenue	707,901	1,501,452	873,376	242,216
Royalty Expense				
Crown royalties	1,329	52,780	52,887	(3,468)
Freehold and overriding royalties	40,764	87,862	28,123	7,933
Total Royalty Expense	$ 42,093	$ 140,642	$ 81,010	$ 4,465
Net Revenue after Royalties	**$ 665,808**	**$ 1,360,810**	**$ 792,366**	**$ 237,751**
Operating and transportation	825,429	904,548	722,065	254,729
General and administrative	615,246	528,364	414,859	281,773
Transaction costs	100,001	142,799	61,426	90,378
Stock based compensation	266,037	102,074	23,443	18,759
Depletion, depreciation, accretion	776,951	517,757	315,062	56,906
Exploration and evaluation expense	-	-	-	-
Impairment	9,817,656	-	-	-
Income (loss) before finance expense and income taxes	$ (11,735,512)	$ (834,732)	$ (744,489)	$ (464,794)
Net finance expense	$ (17,246)	$ 24,678	$ 27,744	$ 15,869
Deferred income tax recovery	(960,000)	-	$ -	(34,415)
Net and Comprehensive loss	**$ (10,758,266)**	**$ (859,410)**	**$ (772,233)**	**$ (446,248)**
Basic income (loss) per share	($0.05)	($0.01)	($0.01)	($0.01)
Average Price				
Natural gas ($ per Mcf)	$ 2.27	$ 3.34	$ 3.75	$ 4.22
Oil and NGL ($ per bbl)	$ 69.42	$ 87.74	$ 71.65	$ 101.78
$ per boe	$ 28.65	$ 44.04	$ 40.23	$ 90.24
Total Assets	**$ 42,533,642**	**$ 46,353,543**	**$ 26,961,591**	**$ 11,874,876**
Total Liabilities	**$ 12,569,006**	**$ 5,897,104**	**$ 8,601,864**	**$ 4,458,463**