BORDER PETROLEUM CORP.

(formerly Border Petroleum Inc.)

MANAGEMENT'S DISCUSSION AND ANALYSIS

July 10, 2012

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CALGARY, ALBERTA T2P 3G2

MANAGEMENT'S DISCUSSION AND ANALYSIS

The financial information presented herein has been prepared on the basis of International Financial Reporting Standards ("IFRS"). Throughout this discussion, percentage changes are calculated using numbers rounded to the decimal to which they appear.

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, 2012, which were prepared in accordance with IFRS. This Management's Discussion and Analysis is dated as of July 10, 2012.

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.

SPECIAL NOTE REGARDING NON-GAAP 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) are non-GAAP measures and do not have standardized meanings prescribed by IFRS.

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.

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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, 2012:

- Entered a new joint venture (the "Joint Venture") with the wholly-owned energy company of the Loon River Cree Nation (the "Nation") to develop up to 17,120 net acres in the Slave Point light oil play in the Red Earth area of northwest Alberta;

- Joint Venture with the Loon River Cree Nation succeeded by the issuance of a permit to Border by Indian Oil and Gas Canada, with the approval of Border and the Nation, covering an expanded 29 1/4 sections (18,720 acres) of Slave Point rights incorporating the Alberta Horizontal Oil New Well Royalty Rate with a 10% minimum;

- Closed a $25,561,500 bought deal equity financing in the Corporation's third quarter for the issuance of 93,150,000 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 (resulting in approximately 224.5 million shares currently outstanding);

- Appointed Peter Fridrich, P.Geol., as Vice President, Exploration (formerly Senior Geologist, NW Alberta District, with Penn West Exploration); and,

- Border commenced drilling its first two Slave Point horizontal wells in the Red Earth area.

OUTLOOK

Border has assembled one of the largest contiguous land interests in the exciting Slave Point play with its 18,720 acre permit on the lands of the Loon River Cree Nation in the Red Earth area of Alberta. The Loon Block contains approximately 120 potential locations based on quarter section spacing which Border operates 100 percent.

Based on the initial results of its first 2 Slave Point wells as detailed above, Border is moving forward with its development plan focused exclusively on its Slave Point light oil opportunities at Red Earth. In this regard, Border plans to drill an additional 1 – 2 wells over the balance of the year with its next well planned for this fall. Capital expenditures with respect to the next phase of development are expected to be funded by a combination of cash and funds generated by current assets.

OPERATIONS

The Corporation's average net daily production was 272 boe/d and 227 boe/d, for the three and twelve months ended March 31, 2012.

Producing Properties

Red Earth/Dawson, Alberta

The Corporation has working interest in 22,053 gross acres (22,012 net) in the Red Earth and Dawson area of northwestern Alberta ("Non-Reserve Lands"). The Corporation re-entered five wells on these lands in its fiscal year ended March 31, 2011. 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. Four of the wells have been fracture stimulated and put on production to date. The Corporation has a well in the Dawson field located at 6-23-80-17W5M. On November 30, 2011, IOGC, with the approval of the Nation, issued an IOGC permit now covering more than 29 sections (18,693 acres) of the Nation's Lands in the Red Earth area of northwestern Alberta including rights in the Slave Point formation. Red Earth/Dawson production during the three and twelve months ended March 31, 2012, averaged 21 bbls/d and 24 bbls/d respectively.

Leduc, Alberta

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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.
The Corporation has an interest in 6,727 gross acres (6,405 net) in the Leduc area of central Alberta. Leduc production for the three and twelve months ended March 31, 2012, averaged 194 boe/d and 147 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 100/16-21-53-18W4 and 100.0% working interest in wells 102/16-21-53-18W4, 00/01-28-53-18W4, 102/01-28-53-18W4 and 100/04-27-053-18W4 which all produce from the Mannville formation. Several Norris wells were down for pump service work during the quarter. The optimization work has increased production from the 102-16-21-53-18W4M well and management is evaluating further optimization work on the remaining Norris wells. Norris production for the three and twelve months ended March 31, 2012, averaged 5 boe/d and 12 boe/d respectively.

Cherhill/Majeau, Alberta

Border has a 37.5% to 100% working interest in 3,200 acres (2,800 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. Cherhill / Majeau production for the three and twelve months ended March 31, 2012, averaged 10 boe/d and 8 boe/d respectively.

Cardiff, Alberta

The Corporation has a 100% working interest in 160 acres in the Cardiff area of central Alberta which consists of one Mannville oil well located at 100/14-34-55-01W5. Cardiff only produced during the third quarter averaging 5 bbls/d and then was shut in after fracture stimulation increased the produced water production.

Pembina/Brazeau, Alberta

Pembina shallow gas production was acquired as part of the Canflame merger commencing July 14, 2011, averaging 41 boe/d for the three months ended March 31, 2012 and 35 boe/d for the period from July 14, 2011 to March 31, 2012.

<u>Non-Producing Properties</u>

Phat City, Montana, USA

The Corporation is party to a sub-participation agreement with Triangle USA Petroleum Corporation Ltd. ("Triangle"), which assigned Triangle's rights in an exploration agreement between Triangle and Hunter Energy LLC ("Hunter"). The agreement requires the Corporation to pay 33 1/3% of the cost to drill one vertical test well on certain joint participation lands consisting of a 33,831 gross acre land position in Montana, United States to earn a 25% non-operating working interest. Hunter has issued a notice of termination of the exploration agreement to Border dated July 25, 2011, with respect to a cash call regarding the drilling of the initial vertical test well under the exploration agreement. By correspondence dated August 2, 2011, the Corporation has contested the notice on grounds that the cash call is improper and does not comply with the exploration agreement. This is an exploration project for Nisku and Bakken oil on the west side of Williston Basin.

<u>PRODUCTION SUMMARY</u>

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	2011	CHANGE	2012	2011	CHANGE
Total Production						
Oil - bbls	**4,671**	3,174	47	**22,322**	11,017	103
Natural gas liquids - bbls	**1,991**	40	4,878	**6,529**	170	3,741
Natural Gas - Mcf	**108,283**	2,222	4,773	**326,047**	11,654	2,698
Total boe	**24,709**	3,584	589	**83,192**	13,130	534
Daily Production						
Oil - bbls per day	**51**	35	46	**61**	30	103
Natural gas liquids - bbls per day	**22**	1	2,100	**18**	1	1,700
Natural Gas - Mcf per day	**1,190**	25	4,660	**891**	32	2,684
Total boe per day	**272**	40	580	**227**	36	531

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For the year ended March 31, 2012, oil production increased 103% to 22,322 bbls compared to11,017 bbls for the same period last year. Natural gas production for the year ended March 31, 2012, was up 2,698% to 326,047 mcf compared to 11,654 mcf for the comparable period last year. Natural gas liquids ("NGLs") increased 3,741% to 6,529 bbls during the twelve months ended March 31, 2012 compared to 170 bbls last year. Total production expressed in boe for the year ended March 31, 2012, increased 534% to 83,192 boe compared to 13,130 boe last year. These increases are mainly due to production associated with the addition of the Canflame merger.

For the three months ended March 31, 2012, oil production increased 47% to 4,671 bbls compared to 3,174 bbls during the same quarter last year. Natural gas production for the three months ended March 31, 2012, was up 4,773% to 108,283 mcf compared to 2,222 mcf for the comparable quarter last year. Natural gas liquids ("NGLs") increased 4,878% to 1,991 bbls during the three months ended March 31, 2012 compared to 40 bbls last year. Total production expressed in boe for the three months ended March 31, 2012, increased 589% to 24,709 compared to 3,584 boe last year. These increases are mainly due to production associated with the recompletion of the 14-32-49-26W4M well and the optimization of the 102-16-21-53-18W4M well and other production.

PRICING SUMMARY

	THREE MONTHS ENDED DECEMBER 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Oil - $ per bbl	**$ 73.06**	$ 83.37	(12)	**$ 84.95**	$ 72.62	17
Natural gas liquids - $ per bbl	**$ 60.88**	$ 86.54	(30)	**$ 64.21**	$ 60.07	7
Natural Gas - $ per Mcf	**$ 2.27**	$ 4.14	(45)	**$ 3.10**	$ 4.16	(25)
$ per boe	**$ 28.65**	$ 77.34	(63)	**$ 39.97**	$ 65.40	(39)

During the year ended March 31, 2012, 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, 2012, the average boe price was $39.97 compared to $65.40 last year. This drop in average boe price is the result of natural gas production that was acquired through the Canflame Energy merger that increased the percentage of natural gas to oil and liquids production to 65% from last year's 15%. Natural gas prices have been extremely low compared to the equivalent oil and liquids prices. 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. With natural gas prices as low as $2.00 per mcf and oil prices often above $100 per barrel, Border's future drilling targets are all light oil wells.

REVENUE

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Oil	**$ 341,263**	$ 264,605	29	**$ 1,896,144**	$ 800,038	137
Natural gas liquids	**121,222**	3,375	3,492	**419,252**	10,212	4,005
Natural Gas	**245,416**	9,211	2,564	**1,009,548**	48,500	1,982
Total Working Interest Revenue	**$ 707,901**	$ 277,191	155	**$ 3,324,944**	$ 858,750	287
$ per boe	**$ 28.65**	$ 77.34	(63)	**$ 39.97**	$ 65.40	(39)

Total revenue for the year ended March 31, 2012, increased 287% totaling $3,324,944 compared to $858,750 last year. This increase was due primarily to the production acquired in the Canflame merger in July 2011. Total revenue when expressed as dollars per boe fell during the year ended March 31, 2012, due to the ratio of natural gas production versus oil and natural gas liquids ("NGLs"). During the three and twelve months ended March 31, 2012, natural gas sales volumes accounted for 73% and 65% respectively, of the total sales. Natural gas prices have been low since late 2008 and have averaged $3.10 per mcf during the year ended March 31, 2012. In this Management's Discussion and Analysis, a barrel of equivalent ("boe") equals six mcf per boe. With natural gas prices averaging $3.10 per mcf, this equates to $18.60 per boe. Currently the Corporation has greater natural gas sales than oil and NGLs that drive the average price per boe downwards. Future drilling plans target light oil production.

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ROYALTY SUMMARY

	THREE MONTHS ENDED MARCH 31 2012	2011	% CHANGE	TWELVE MONTHS ENDED MARCH 31 2012	2011	% CHANGE
Crown	**$ 1,329**	$ 26,579	(95)	**$ 103,527**	$ 51,298	102
Overriding and Freehold	**40,764**	12,293	232	**164,682**	60,718	171
Total Royalty Expense	**42,093**	38,872	8	**268,209**	112,016	139
$ per boe	**$ 1.70**	$ 10.85	(84)	**$ 3.22**	$ 8.53	(62)
Expense rate - % of total working interest revenue	**6**	14	(57)	**8**	13	(38)

Total royalties paid for the year ended March 31, 2012, increased by 139% to $268,209 compared to $112,016 compared to last year. On a $ per boe basis, total royalties fell by 62% to $3.22 for the year ended March 31, 2012, compared to $8.53 per boe last year. Royalties expressed as a percentage of total working interest revenue was 8% for the year ended March 31, 2012, compared to 13% last year. Natural gas at March 31, 2012, accounts for 65% of the Corporation's revenue and due to the low prices and the sliding royalty scale and the gas cost allowance credits, gas Crown royalties remain low.

For the three months ended March 31, 2012, royalties increased by 8% to $42,093 from $38,872 for the comparable quarter last year. On a $ per boe basis, total royalties fell by 84% to $1.70 for the three months ended March 31, 2012, compared to $10.85 per boe last year. This is due primarily to the increase of natural gas sales which, as explained above, greatly reduces per boe costs. Royalties expressed as a percentage of total working interest revenue was 6% for the three months ended March 31, 2012, compared to 14% during the same quarter last year.

OPERATING AND TRANSPORTATION EXPENSES

	THREE MONTHS ENDED MARCH 31 2012	2011	% CHANGE	TWELVE MONTHS ENDED MARCH 31 2012	2011	% CHANGE
Production expenses	**$ 636,043**	$ 270,064	136	**$ 2,169,056**	$ 572,555	279
Transportation and gathering	**119,398**	24,344	390	**361,426**	109,968	229
	755,441	294,408	157	**2,530,482**	682,523	271
Workover expenses	**69,988**	72,906	(4)	**176,289**	110,444	60
Total Production Expenses	**$ 825,429**	$ 367,314	125	**$ 2,706,771**	$ 792,967	241
$ per boe Total production expenses	**$ 33.41**	$ 102.48	(67)	**$ 32.54**	$ 60.39	(46)
Production, transportation & gathering	**$ 30.57**	$ 82.14	(63)	**$ 30.42**	$ 51.98	(41)
Workover expenses	**$ 2.83**	$ 20.34	(86)	**$ 2.12**	$ 8.41	(75)
Expense rate - % of total working interest revenue	**117**	133	(12)	**81**	92	(12)

Production expenses, excluding workovers, for the year ended March 31, 2012, increased 271% to total $2,530,482 compared to $682,523 last year. The transportation and gathering expense component of the production costs for the year ended March 31, 2012, increased 229% to $361,426 compared to $109,968 last year due to the closure of the Rainbow pipeline, which resulted in higher cost transportation arrangements. Workovers on the Norris wells during the first quarter of this year plus the second quarter upgrading of the Leduc central battery and wells, resulted in costs totalling $176,289 versus the $110,444 spent during the same period last year. Total production expenses for the year ended March 31, 2012, increased 241% to $2,706,771 compared to $792,967 last year. This increase is directly attributable to the 534% increase in production volumes and operational activities from the Canflame Energy Ltd. acquisition. Total production expenses, expressed as a $ per boe during the year ended March 31, 2012, averaged $32.54 per boe falling 46% from last year's average of $60.39 per boe due to higher production volumes.

Production expenses, excluding workovers, for the three months ended March 31, 2012, increased 157% to total $755,441 compared to $294,408 for the comparable quarter last year. The transportation and gathering expense component of the production costs for the three months ended March 31, 2012, increased 390% to $119,398 compared to $24,344 for the comparable quarter last year. These expenses increased as a result of operating two new sour wells acquired in the Canflame

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merger and the trucking of fluids associated produced water from these wells and the 14-32-49-26W4M well. Total production expenses for the three months ended March 31, 2012, increased 125% to $825,429 compared to $367,314 during the comparable quarter last year. Total production expenses, expressed as a $ per boe during the three months ended March 31, 2012, averaged $33.41 per boe falling 67% from last year's average of $102.48 per boe due to higher production volumes.

GENERAL AND ADMINISTRATIVE EXPENSES

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
General and administration	**$ 615,246**	$ 382,249	61	**$ 1,840,242**	$ 843,574	118
Transaction costs	**100,001**	-	n/a	**394,604**	-	n/a
	715,247	382,249	87	**2,234,846**	843,574	165
$ per boe	**$ 28.95**	$ 106.65	(73)	**$ 26.86**	$ 64.25	(58)
Expense rate - % of total working interest revenue	**101**	138	(27)	**67**	98	(32)

General and administrative expenses for the year ended March 31, 2012, increased by 165% totaling $2,234,846 compared to $843,574 last year. During this twelve months, total general and administration expense per boe fell 58% to $26.86 per boe compared to $64.25 per boe last year. Legal fees and associated costs totaling $394,604 have also been incurred in the year ended March 31, 2012, related to the business combination with Canflame Energy Ltd. that closed on July 13, 2011. Costs to assimilate the Canflame accounting and land records added an additional cost of approximately $100,000. The cost of office moves, higher office lease costs, as well as associated computerization and communication costs contributed to the increased G&A costs this year. During the last half of the year additional costs were incurred as Border focused on the Red Earth resource play. Specialized services in finance, geological, engineering and on-site field consultants added approximately $250,000 of costs that were not incurred last year.

General and administration costs were low in the prior year ending March 31, 2011 as the Corporation had the President and CEO as the only employee for several months of the year until additional salaried employees were added, including a Chief Financial Officer, Chief Operating Officer, Vice President of Exploration and two accounting/administrative staff.

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.

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	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Finance income						
Interest income	**$ 74,599**	$ 26,432	182	**$ 183,758**	$ 26,432	595
	74,599	26,432	182	**183,758**	26,432	595
Finance expenses						
Interest expense	**(333)**	-	n/a	**3,714**	**-**	n/a
Interest expense on convertible debentures	**-**	16,441	(100)	**-**	125,056	(100)
Interest expense on note payable	**27,147**	-	n/a	**106,751**	-	n/a
Loss on convertible debentures	**-**	55,549	(100)	**-**	55,549	(100)
Accretion on convertible debentures	**-**	6,201	n/a	**-**	50,308	n/a
Accretion on convertible note payable	**26,040**		n/a	**102,398**	-	n/a
Accretion of decommissioning provisions	**4,499**	(4,846)	193	**21,940**	1,048	1,994
	57,353	73,345	(22)	**234,803**	231,961	1
Finance income (expense) cash items	**74,932**	26,432	183	**180,044**	26,432	581
Finance expense non-cash items	**(57,686)**	(73,345)	21	**(231,089)**	(231,961)	-
Net finance income (expense)	**17,246**	(46,913)	137	**(51,045)**	(205,529)	(75)
$ per boe - finance income (expense) cash items	**$ 3.03**	$ 7.38	(59)	**$ 2.16**	$ 2.01	n/a
$ per boe - finance expense non-cash items	**$ (2.33)**	$ (20.46)	(89)	**$ (2.78)**	$ 17.67	(116)

DEPLETION AND DEPRECIATON

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Depletion, depreciation	**$ 776,951**	$ 101,503	665	**$ 1,666,676**	$ 253,864	557
Impairment	**9,817,656**	-	n/a	**9,817,656**	-	n/a
	$ 10,594,607	$ 101,503	10,338	**$ 11,484,332**	$ 253,864	4,424
$ per boe - Depletion, depreciation	**$ 31.44**	$ 28.32	11	**$ 20.03**	$ 19.33	4
- Impairment	**$ 397.33**	-	n/a	**$ 118.01**	-	n/a
Expense rate - % of working interest revenue	**1,497**	37	3,945	**345**	30	1,051

Depletion and depreciation expense for the year ended March 31, 2012, totaled $1,666,676 or $20.03 per boe compared to $253,864 for the same period last year. The change in depletion during this year compared to last year is primarily the result of the acquisition of Canflame Energy Ltd., the Leduc farm-in agreement and the drilling and completion of a horizontal well in the Leduc area and two horizontal wells in the Red Earth area of Alberta.

Included in depletion are impairment losses of $9.6 million attributable to the Leduc area Cost Generating Unit (CGU) and $233,000 to the Cardiff Area CGU. The Leduc impairment was caused by changes in forecasted commodity prices that reflected the continued weakness in natural gas prices, available well results to date and a change in reserve evaluators. This resulted in lower estimated recoverable reserve amounts and lower net present values in the Corporation’s March 31, 2012 independent reserve evaluation. The Cardiff impairment was due to the shutting-in of the only well in this CGU. During the period ended March 31, 2012, $34,666,000 of future development costs related to proved and probable reserves were included in costs subject to depletion.

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SHARE CAPITAL

Issued and Outstanding Common Shares

The following table states the issued and outstanding share capital of the Corporation:

	March 31, 2012		
	Number		Stated Value
Balance, beginning of period	70,586,293	$	15,965,618
Issuance to acquire Canflame A&B shares (1)	30,312,232		9,699,914
Issuance for Canflame debentures & accrued interest (1)	6,225,594		1,992,190
Issuance of common shares (2)	81,000,000		17,010,000
Issuance of flow-through shares (2)	24,000,000		6,000,000
Issuance of common shares (3)	12,150,000		2,551,500
Flow-through share premium			(960,000)
Exercise of warrants	263,834		50,675
Share issue costs			(1,957,196)
Balance, end of period	**224,537,953**	**$**	**50,352,701**

(1) 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"). Pursuant to the Transaction: (i) the holders of debentures of Canflame ("Canflame Debentures") received 6,225,594 common shares of the Corporation; and (ii) the holders of common shares of Canflame ("Canflame Shares") received four common shares for each Canflame Share, resulting in the issuance of 30,312,232 common shares of the Corporation for a total of 36,537,826 common shares of Border to the holders of Canflame Debentures and Canflame Shares combined. All other existing options, warrants or securities convertible into Canflame Shares were cancelled. Seventy five percent (75%) of the Border Shares issued to the shareholders of Canflame are subject to a voluntary hold period of four months from the date of closing of the Transaction. As part of the acquisition of Canflame, 6,062,446 Border common shares have been placed into escrow, and will be released only upon the resolution of a pre-existing legal action of which Canflame has been named as the defendant. If there is any loss suffered as a result of the legal actions, one Border common share will be cancelled and returned to treasury for each $0.30 of loss. These Border common shares are contingently issuable based on the outcome of the legal actions and management has determined that the likelihood of any loss occurring as being remote. Transaction costs of $394,604 related to this transaction were incurred and have been charged against income during the year ending March 31, 2012.

(2) 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.

(3) 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 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.

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Warrants

	March 31, 2012		March 31, 2011	
	Number of Warrants	**Weighted Average Exercise Price**	**Number of Warrants**	**Weighted Average Exercise Price**
Outstanding, beginning of period	**14,427,500**	**$ 0.33**	8,250,000	$ 0.10
Reduced by way of 4:1 consolidation	**-**	**-**	(6,187,500)	0.10
	14,427,500	**0.33**	2,062,500	0.40
Issued (1 & 2)	**2,343,000**	**0.21**	14,427,500	0.33
Exercised	**(263,834)**	**0.19**	-	-
Expired	**-**	**-**	(2,062,500)	0.10
Outstanding and exercisable, end of perio(	**16,506,666**	**$ 0.32**	14,427,500	$ 0.33

(1) Upon the closing November 30, 2011 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.

(2) As part of the common shares issued in December 2010, the Corporation issued 987,500 warrants to purchase common shares of the Corporation at a price of $0.15 for a period of 2 years. The fair value ascribed to the warrants was $38,094. In addition, as part of the February 2, 2011 financing, the Corporation issued 12,000,000 warrants to purchase common shares of the Corporation at a price of $0.35 for a period of 18 months. The fair value ascribed to the warrants was $521,690. The Agent for the offering was granted broker options to purchase 1,440,000 units, with each broker option entitling the holder to acquire one unit at a price of $0.25 per unit for a period of 18 months from the closing date. Each unit consists of one common share and one half of one common share purchase warrant with each warrant entitling the holder thereof to purchase one common share at a price of $0.35 per share for a period of 18 months from the option grant. In addition, the warrants will expire and be of no further force and effect if not exercised within 10 days of receipt of notice from the Corporation that the 20 day volume weighted average price of the common shares is greater than $0.55. The value ascribed to the broker's options and embedded warrants was calculated to be $135,642 and is included as part of warrants.

STOCK BASED COMPENSATION

The Corporation has an established stock option plan (the "Plan") which is administered by the Board of Directors, allowing the Board of Directors to grant stock options. The Corporation adopted a 10% Rolling Stock Option Plan, which allows for the purchase of up to 10% of the outstanding common shares of the Corporation.

Additionally, 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.

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	March 31, 2012		March 31, 2012	
	Number	**Weighted Average Exercise Price**	**Number**	**Weighted Average Exercise Price**
Outstanding, beginning of period	**2,923,750**	**$ 0.25**	7,295,000	$ 0.10
Cancelled or expired	**(537,500)**	**0.25**	(4,200,000)	$ 0.10
	2,386,250	**$ 0.25**	3,095,000	$ 0.10
Adjust for 4:1 consolidation (*)	**-**	**-**	(2,321,250)	-
	2,386,250	**$ 0.25**	773,750	$ 0.40
Granted	**12,550,000**	**0.23**	2,200,000	$ 0.19
Forfeited	**-**	**--**	(50,000)	$ 0.10
Outstanding, end of period	**14,936,250**	**$ 0.23**	2,923,750	$ 0.25
Exercisable, end of period	**1,865,417**	**$ 0.26**	1,496,979	$ 0.29

(*) As a result of the 4:1 consolidation of the Corporation's outstanding shares, the stock options were also consolidated on a 4:1 basis and repriced at $0.40 per common share.

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Stock based compensation	**$ 266,037**	$ 127,769	108	**$ 410,314**	$ 140,013	193
$ per boe	**$ 10.77**	$ 35.65	(70)	**$ 4.93**	$ 10.66	(54)
Expense rate - % of working interest revenue	**38**	46	(18)	**12**	16	(25)

Stock-based compensation for the year ended March 31, 2012, was $410,314 or $4.93 per boe compared to $140,013 or $10.66 per boe for last year. The Corporation calculates the stock based compensation using the Black-Scholes option-pricing model. For the year ended March 31, 2012, 12,550,000 new options were granted and 537,500 options were forfeited. At March 31, 2012, there were 1,865,417 options that were exercisable.

AVERAGE SHARES OUTSTANDING

The weighted average number of shares outstanding ended March 31, 2012, totaled 135,394,501 compared to 27,785,400 (post 4:1 share consolidation) at March 31, 2011. On September 14, 2010, the TSX Venture Exchange provided final acceptance of the consolidation of the Corporation's shares on a basis of one common share for each four pre-consolidation common shares.

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

Common shares	224,537,953
Stock options	14,936,250
Warrants	16,506,666

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NET LOSS AND COMPREHENSIVE LOSS

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Net income (loss) for period	**$ (10,758,266)**	$ (717,162)	1,400	**$ (12,836,158)**	$ (1,301,488)	886
Income (Loss) per share	**$ (0.05)**	$ (0.01)	400	**$ (0.09)**	$ (0.05)	80

A net loss and comprehensive loss of ($12,836,158) was recorded for the year ended March 31, 2012, compared to a net loss and comprehensive loss of ($1,301,488) for the same period last year. This was due primarily to higher operating costs, general and administrative costs and an increase in depletion expense, and the impairment loss.

NET PETROLEUM AND NATURAL GAS REVENUE

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	**2011**	**CHANGE**	**2012**	**2011**	**CHANGE**
Petroleum & Natural Gas Revenue	**$ 707,901**	$ 277,191	155	**$ 3,324,944**	$ 858,750	287
Less:						
Royalties	**42,093**	38,872	8	**268,209**	112,016	139
Production expenses	**755,441**	294,408	157	**2,530,482**	682,523	271
Workover expenses	**69,988**	72,906	(4)	**176,289**	110,444	60
Net Petroleum & Natural Gas Revenue	**$ (159,621)**	$ (128,995)	24	**$ 349,964**	$ (46,233)	857
$ per boe	**$ (6.46)**	$ (35.99)	(82)	**$ 4.21**	$ (3.52)	220

Gross revenue from petroleum and natural gas increased 287% to total $3,324,944 for the year ended March 31, 2012, compared to $858,750 for the same period last year. Net revenue after royalties, production and workover expenses increased 857% for the year ended March 31, 2012, to $349,964 compared to a loss of ($46,233) for last year.

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NETBACKS

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	2011	CHANGE	2012	2011	CHANGE
$ per boe						
Working Interest Revenue	**$ 28.65**	$ 77.34	(63)	**$ 39.97**	$ 65.40	(39)
Royalties	**1.70**	10.85	(84)	**3.22**	8.53	(62)
Production expenses	**30.57**	82.14	(63)	**30.42**	51.98	(41)
Workover expenses	**2.83**	20.34	(86)	**2.12**	8.41	(75)
Total after royalties and production expenses	**$ (6.45)**	$ (35.99)	(81)	**$ 4.21**	$ (3.52)	(220)
General and administration and transaction costs	**28.95**	106.65	(73)	**26.86**	64.25	(58)
Finance income cash items	**3.03**	7.38	(59)	**2.16**	2.01	7
Total Corporate Netbacks	**$ (32.37)**	$ (135.26)	(76)	**$ (20.49)**	$ (65.76)	(69)
Non-Cash Items						
Depletion, depreciation and accretion	**31.44**	28.32	11	**20.03**	19.33	4
Impairment loss	**397.33**	-	n/a	**118.01**	-	n/a
Stock based compensation	**10.77**	35.65	(70)	**4.93**	10.66	(54)
Finance expense non-cash items	**2.33**	20.46	(89)	**2.78**	(17.67)	(116)
Total Netbacks after non-cash items	**$ (474.24)**	$ (219.69)	116	**$ (166.24)**	$ (78.08)	113

Field netbacks for the year ended March 31, 2012, were $4.21 per boe compared to a loss of ($3.52) per boe for last year. Total netbacks after non-cash items for the year ended March 31, 2012, were losses of ($166.24) per boe compared to ($78.08) per boe for last year.

CAPITAL ADDITIONS

	THREE MONTHS ENDED MARCH 31		%	TWELVE MONTHS ENDED MARCH 31		%
	2012	2011	CHANGE	2012	2011	CHANGE
Exploration and evaluation assets	**$ (284,899)**	$ 72,609	(492)	**$ 4,388,106**	$ 181,387	2,319
Property and equipment						
Drilling and completions	**7,245,914**	308,162	2,251	**10,078,271**	2,049,732	392
Production equipment and facilities	**1,533,031**	195,179	685	**2,262,641**	938,290	141
Property acquisitions	**-**	-	n/a	**17,326,419**	-	n/a
Asset retirement	**174,995**	281,075	(38)	**304,653**	194,244	57
Furniture and equipment	**(7,055)**	4,835	n/a	**17,249**	31,174	(45)
Total	**$ 8,661,986**	$ 861,860	905	**$ 34,377,339**	$ 3,394,827	913

Total asset additions were $34,377,339 for the year ended March 31, 2012, compared to $3,394,827 for the year ended March 31, 2011. These additions included $ 304,653 of non-cash decommissioning adjustments. The additions to capital expenditures this year related to acquisitions are as follows: (For more details regarding these acquisitions, see note 4 in the Border Petroleum Corp. consolidated Financial Statements, March 31, 2012 and March 31, 2011.)

a)	Canflame Energy Ltd.	$14,880,908
b)	Leduc farm-in purchase	2,572,265
		$17,453,173

During the last quarter ended March 31, 2012, the Corporation focused capital spending in the Red Earth area of Alberta, drilling and completing two short-leg, horizontal exploratory wells. In the first half of the year, Border established a new core area in Leduc, Alberta by acquiring the farm-in agreement from a private company and merging with Canflame Energy Ltd. and spending $2,436,313 drilling and completing a horizontal well in the Leduc area.

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BANK DEBT

The Corporation has no bank debt outstanding under a demand revolving operating loan at March 31, 2012, (March 31, 2011 - $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. The credit facility is secured by a general security agreement and a guarantee of a subsidiary corporation that was formed to complete the merger with Canflame Energy Ltd.

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, 2012, Border had working capital (current assets minus current liabilities) of $6,217,603 compared to working capital of $3,338,129 at March 31, 2011.

Pursuant to its joint venture with the Loon River Cree Nation, as well as its current land holdings at its Red Earth and Leduc core areas, Border has a significant drilling portfolio. In this regard, Border plans to undertake new capital projects at Red Earth and Leduc over the next 12 months. Consequently, the timing of anticipated cash from operating activities will not provide the funds to reduce the working capital deficiency and to satisfy the Corporation's forecasted capital requirements for the year. In order for the Corporation to fund its capital expenditure budget, the Corporation completed a debt and an equity financing.

In July 2011, the Corporation entered into a credit facility agreement for a demand revolving operating loan of $3,500,000. At March 31, 2012, the Corporation had not drawn from the Credit Facility.

On November 30, 2011, the Corporation closed a bought deal offering of common shares (the "Common Shares") and flow-through common shares ("Flow-Through Shares"), the Corporation and the syndicate of underwriters led by Canaccord Genuity Corp. and including Macquarie Capital Markets Canada Ltd., National Bank Financial Inc., Dundee Securities Ltd., Haywood Securities Inc. and Fraser Mackenzie Limited (collectively the "Underwriters") have agreed to increase the size of the offering to an aggregate of 81,000,000 Common Shares at a price of $0.21 per Common Share and 24,000,000 Flow-Through Shares at a price of $0.25 per Flow-Through Share for aggregate gross proceeds of $23,010,000 (the "Offering").

On December 14, 2011, the Underwriters exercised the full Over-Allotment Option that they were granted with the November 30, 2011 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 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.

	MARCH 31 2012	**MARCH 31 2011**	**% CHANGE**
Cash	**$12,972,419**	$ 3,811,333	240
Accounts receivable and prepaid expenses	**1,557,612**	374,960	315
Accounts payable and accrued liablities	**(9,075,357)**	(813,749)	1,015
Flow-through share premium liability	**-**	(34,415)	n/a
Investment in secured debt	**762,929**	-	n/a
	$ 6,217,603	$ 3,338,129	86

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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, 2012, the Corporation incurred $291,478 (March 31, 2011 - $NIL) on legal services, of which $193,705 is included in general and administrative expense or transaction costs, and $5,686 in accounts payable and accrued liabilities at March 31, 2012.

During the year ended March 31, 2011, $50,000 in management fees, which is included in general and administrative expenses were paid to officers and or companies controlled by officers and directors of the Company. In addition, during the year ended March 31, 2011, $89,280 in remuneration, fees and rent which is included in general and administrative expenses were paid to former officers and or companies controlled by former officers and directors of the Company. These amounts are recorded at the exchange amount of the consideration established and agreed to by the related parties.

During the year ended March 31, 2011, the Company paid $30,000 to a company controlled by two former directors as per the terms of a participation agreement whereby Border paid a fee to participate in a farm-out agreement.

During the year ended March 31, 2011, current officers and directors of the Corporation participated in the private placement of secured convertible debentures and purchased $1,089,000 of the debentures. As part of the terms of a private placement in February 2011, all amounts outstanding (including accrued interest) of the convertible debentures were converted into common shares of the Corporation as per the original conversion terms. There was no similar financing completed during the year ended March 31, 2012.

During the year ended March 31, 2011, two directors participated in a $600,000 bridge financing. The directors invested $400,000. The bridge financing was secured by a general security agreement over the assets of the Corporation and the Lenders were issued fixed and floating charge debentures and promissory notes for the amount of the bridge financing. The promissory notes were convertible at any time at the option of the Lenders into convertible debentures on the same terms as the debenture offering.

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 AND OTHER INSTRUMENTS (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, accounts payable and accrued liabilities, and note payable approximate their carrying value.

At March 31, 2012, 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 venture 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 venture 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 venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. The Corporation does not typically obtain collateral from joint venture 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 venture 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 period ended March 31, 2012 and there is $595,949 in accounts receivable outstanding greater than 90 days at March 31, 2012, which the Corporation would consider past due under normal conditions. Of this balance, $330,202 is due from one joint venture partner.

Cash balances consist of amounts on deposit with banks where bank overdraft consists of outstanding cheques issued in excess of cash. The Corporation manages the credit exposure of cash by selecting financial institutions with high credit ratings.

Total credit risk at March 31, 2012 is comprised of $1,500,909 in accounts receivable, $173,033 in lease reclamation deposits, $762,929 in investment in secured debt and $12,972,419 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, 2012.

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, 2012.

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 note payable and investment in secured debt 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.

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 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. 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.

CHANGES IN ACCOUNTING POLICIES AND NEW ACCOUNTING PRONOUNCEMENTS

Adoption of International Financial Reporting Standards

The Corporation prepared its March 31, 2012 financial statements in accordance with IFRS 1 "First Time Adoption of International Financial Reporting Standards", as issued by the International al Accounting Standards Board ("IASB"). Previously, the Company prepared its financial statements in accordance with previous GAAP.

The Company's IFRS accounting policies are described in Note 3 to the audited March 31, 2012 financial statements. In accordance with IFRS 1, the Company's transition date to IFRS was April 1, 2010, and therefore the comparative information for 2011 has been prepared and restated in accordance with Border's IFRS policies. For a full disclosure of the reconciliation between the Company's 2011 Previous GAAP financial statements and the 2011 IFRS financial statements, refer to note 22 of the March 31, 2012 financial statements.

Following is a discussion of the of the significant accounting policy changes for Border:

(i) Exploration and evaluation assets

Under IFRS, E&E costs are recognized as exploration and evaluation assets. The Company followed full cost accounting under Canadian GAAP and classified all exploration and evaluation costs as oil and natural gas property and equipment. The effect of this change results in a reclassification of exploration and evaluation costs from oil and natural gas property and equipment to exploration and evaluation assets. As well, pre-license seismic and other costs incurred are expensed directly to results of operations. Under Canadian GAAP, such pre-license and seismic costs were capitalized as part of petroleum and natural gas property and equipment.

Exploration and evaluation assets increased and property and equipment decreased by $1,185,451 at March 31, 2011.

(ii) Impairment

Under Canadian GAAP, impairment was measured by comparing the carrying amounts of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves and the cost less impairment of unproved properties. Under IFRS, the aggregate carrying value is compared against the expected recoverable amount of each cash-generating unit, generally by reference to the present value of the future net cash flows expected to be derived from production of commercial reserves. If the carrying value of a cash-generating unit exceeds its recoverable amount, then an impairment loss shall be recognized. Additionally, an impairment loss from a prior period may be reversed in a subsequent period if impairment no longer exists or has decreased.

Impairments were recorded on two of the Corporation's cash-generating units principally due to decreasing natural gas prices and reserve revisions during 2012. The amounts of these impairments were $9.6 million attributable to the Leduc cost-generating unit and $233,000 attributable to the Cardiff cost-generating unit for the year ended March 31, 2012.

The impairments reduced property and equipment with corresponding charges to depletion. There were no impairments recorded for the year ended March 31, 2011.

(iii) Decommissioning provisions

Under Canadian GAAP, asset retirement obligations were measured at fair value, incorporating market assumptions and discount rates based on the Company's credit-adjusted risk-free rate. Adjustments were made to asset retirement obligations for changes in the timing or amount of the cash flows and the unwinding of the discount. However, changes in discount rates alone did not result in a re-measurement of the provision. Under Canadian GAAP, changes in estimates related to asset retirement obligation discriminated changes in estimates that increased the liability from those that decreased it. Upward revisions in the estimates of undiscounted cash flows were required to be discounted using the current credit-adjusted risk-free rate and downward revisions in the estimated cash flows were required to be discounted using the credit-adjusted risk-free rate employed when the original liability was recognized.

Under IFRS, future cash outflows are estimated as they arise and are discounted at the current appropriate discount rate. Both the cash flows to settle the obligation and the discount rate are considered at each reporting period are adjusted to the appropriate estimate at that point in time. Under IFRS, the estimated cash flow to abandon and remediate the wells and facilities is risk adjusted; therefore the provision is discounted at a risk-free rate. In addition, under Canadian GAAP, accretion of the discount was either included in the depletion and depreciation expense or shown as a separate expense item. Under IFRS, it is included in finance expenses.

Upon application of IFRS, decommissioning liabilities increased by $41,386 and accretion expense decreased by $18,952 during the year ended March 31, 2011.

(iv) Depletion Policy

Upon transition to IFRS, the Corporation adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion was done on the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (i.e fields or combinations thereof).

The use of proved plus probable reserve bases for calculating depletion resulted in a decrease to depletion expense of $435,834 for the year ended March 31, 2011.

(v) Flow- through shares

Flow-through shares are unique Canadian tax incentives which are the subject of specific guidance under Canadian GAAP. There is no equivalent IFRS guidance. Therefore, the Corporation has adopted a policy whereby the premium paid for flow-through shares in excess of the estimated market value of the Corporation's shares without the flow-through feature, at the time of issue, is credited to other liabilities ("flow-through share premium") and is included in income at the time the qualifying expenditures are made. Under Canadian GAAP, the gross proceeds received on flow-through share issuances are initially recorded as share capital. When the expenditures are incurred and the tax deductions are renounced to subscribers, the Corporation has adopted an IFRS policy that the deferred tax liability is recorded through a charge to income tax expense less the reversal of the flow-through share premium previously reported. Under Canadian GAAP, the carrying value of the shares issued was reduced, and the future income tax liability of the Corporation was increased, by the estimated value of the renounced income tax deductions when the related flow through expenditures were renounced to the subscribers and the prescribed forms were filed with the Canada Revenue Agency.

As a result, the Corporation recorded $222,140 as a flow-through share premium as at March 31, 2011 and $nil as at April 1, 2010 with a corresponding decrease to share capital, reduced at March 31, 2011, by $187,725 for effect of qualifying expenditures to date. The tax effect of flow through shares of $277,675 originally recorded under Canadian GAAP has also been reversed. At March 31, 2012, the Corporation recorded $nil as a flow-through share premium liability as the full amount of qualifying expenditures were incurred during the quarter ended March 31, 2012.

(vi) Statement of cash flows for previous periods

The transition from former Canadian GAAP to IFRS had no material effect upon the reported cash flows generated by the Corporation, and as such, no reconciliation of march 31, 2011 statement of cash flows has been presented.

(vii) Net finance expense

Under IFRS, all amounts related to interest earned and/or paid has been reclassified to net finance expense on the statement of loss and comprehensive loss.

(viii) Income tax

Any change to income tax reporting is predominantly caused by changes in the carrying value of assets, not due to the change in income tax accounting methodology, with the exception of flow-through shares. IFRS requires that all deferred taxes be disclosed as non-current assets or liabilities and designated as deferred taxes. As the Corporation is not recognizing deferred tax assets in excess of deferred tax liabilities for all periods shown, the only adjustment to deferred tax expense (recovery) relates to the reversal of the flow-through share premium liability.

Recent Accounting Pronouncements

IFRS 9 Financial Instruments

The IASB intends to replace IAS 39, “Financial Instruments: Recognition and Measurements” (“IAS 39”) with IFRS 9, “Financial Instruments” (“IFRS 9”). IFRS 9 will be published in three phases, of which the first phase has been published. For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used. For financial liabilities, the approach to the fair value option may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity’s own credit risk. IFRS 9 is effective for annual periods beginning on or after January 1, 2015, but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 9.

IFRS 10, Consolidation

IFRS 10 was issued on May 12, 2011. This standard requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12, "Consolidation-Special Purpose Entities", and parts of IAS 27, "Consolidated and Separate Financial Statements". The standard is effective for fiscal periods beginning on or after January 1, 2013, but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 10.

IFRS 11, Joint Arrangements

IFRS 11 was issued on May 12, 2011. This standard requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supercedes IAS 31, "Interests in Joint Ventures", and SIC-13, "Jointly Controlled Entities-Non-monetary Contributions by Venturers". The standard is effective for fiscal periods beginning on or after January 1, 2013, but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 11.

IFRS 12, Disclosure of Interests in Other Entities

IFRS 12 was issued on May 12, 2011. This standard establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity’s interests in other entities. The standard is effective for fiscal periods beginning on or after until January 1, 2013, but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 12.

IFRS 13, Fair Value Measurement

IFRS 13 was issued on May 12, 2011. This is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is 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. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The standard is effective for fiscal periods beginning on or after January 1, 2013 but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 13.

IAS 1, Presentation of Financial Statements

In June 2011, the IASB issued an amendment to IAS 1 requiring companies to group items presented within other comprehensive income based on whether they may be subsequently reclassified to income or loss. Retrospective application of this amendment is effective for fiscal years beginning on or after July 1, 2012, with earlier adoption permitted. No significant impact to the Corporation's financial statements is anticipated upon implementation of the amended standard.

Amendments to Other Standards

In addition, there have been amendments to existing standards, including IAS 27, "Consolidated and Separate Financial Statements", and IAS 28, "Investments in Associates". IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 to 12. These amended standards are effective for fiscal years beginning on or after January 1, 2013, but are available for early adoption. The Corporation has yet to assess the full impact of these amendments.

BUSINESS RISKS AND UNCERTAINTIES

Border Petroleum Corp. 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 Petroleum Corp. 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 Petroleum Corp., 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 Petroleum Corp. 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 Petroleum Corp. 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 July 10, 2012.

ADDITIONAL INFORMATION

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

ABBREVIATIONS

Oil and Natural Gas Liquids		***Natural Gas***	
bbls	Barrels	Mcf	thousand cubic feet
Mbbls	thousand barrels	MMcf	million cubic feet
bbls/d	barrels of oil per day	Mcf/d	thousand cubic feet per day
boe/d	barrels of oil equivalent per day	m3	cubic meters

Oil and Natural Gas Liquids		*Natural Gas*
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	

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

Border Petroleum Corp.
Management's Discussion & Analysis

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 31/2012 Q4	THREE MONTHS ENDED DEC 31/2011 Q3	THREE MONTHS ENDED SEPT 30/2011 Q2	THREE MONTHS ENDED JUN 30/2011 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 per day)	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 and impairment	10,594,607	517,757	315,062	56,906
Income (loss) before finance expense and income taxes	$ (11,735,512)	$ (834,732)	$ (744,489)	$ (464,794)
Net finance (income) 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**

Border Petroleum Corp.
Management's Discussion & Analysis

SUMMARY OF QUARTERLY RESULTS – continued

	THREE MONTHS ENDED MAR 31/2011 Q4	THREE MONTHS ENDED DEC 31/2010 Q3	THREE MONTHS ENDED SEPT 30/2010 Q2	THREE MONTHS ENDED JUNE 30/2010 Q1
Total Production Volumes				
Natural gas (Mcf)	2,222	2,525	3,365	3,546
Oil and NGL (bbl)	3,214	2,402	3,109	2,462
Combined (boe)	3,584	2,822	3,670	3,053
Daily Production				
Natural gas (Mcf per day)	25	27	37	39
Oil and NGL (bbl perday)	36	26	34	27
Combined (boe per day)	40	31	40	34
Gross Revenue				
Natural Gas	$ 9,211	$ 10,301	$ 13,967	$ 15,020
Oil and liquids	267,980	169,946	206,242	166,083
Total PNG Revenue	277,191	180,247	220,209	181,103
Royalty Expense				
Crown royalties	26,579	6,834	18,192	(307)
Freehold and overriding royalties	12,293	11,769	18,910	17,746
Total Royalty Expense	$ 38,872	$ 18,603	$ 37,102	$ 17,439
Net Revenue after Royalties	**$ 238,319**	**$ 161,644**	**$ 183,107**	**$ 163,664**
Operating and transportation	367,314	152,655	109,688	163,310
General and administrative	382,249	113,478	137,096	210,751
Transaction costs	-	-	-	-
Stock based compensation	127,769	6,897	7,414	(2,067)
Depletion, depreciation, accretion	101,502	72,951	75,699	3,712
Income (loss) before finance expense and income taxes	$ (740,515)	$ (184,337)	$ (146,790)	$ (212,042)
Net finance expense	$ 46,911	$ 58,575	$ 73,961	$ 26,082
Deferred income tax recovery	(70,267)	(117,458)	-	-
Net and Comprehensive loss	**$ (717,159)**	**$ (125,454)**	**$ (220,751)**	**$ (238,124)**
Basic income (loss) per share	($0.01)	($0.01)	($0.01)	($0.00)
Average Price				
Natural gas ($ per Mcf)	$ 4.15	$ 4.08	$ 4.15	$ 4.24
Oil and NGL ($ per bbl)	$ 83.39	$ 70.75	$ 66.34	$ 67.46
$ per boe	$ 77.34	$ 63.87	$ 60.00	$ 59.32
Total Assets	**$ 9,004,471**	**$ 4,275,573**	**$ 2,842,948**	**$ 3,204,658**
Total Liabilities	**$ 1,335,998**	**$ 3,515,574**	**$ 2,832,875**	**$ 2,981,248**

*comparative per share amounts have been adjusted for 4:1 share consolidation